EUB Alberta Energy and Utilities Board
640 - 5 Avenue SW Calgary, Alberta Canada T2P 3G4 Tel 403 297-8311 Fax 403 297-7336 www.eub.gov.ab.ca

Directive 017

Revised edition May 7, 2007

Measurement Requirements for Upstream Oil and Gas Operations

The Alberta Energy and Utilities Board (EUB/Board) has approved this directive on May 7, 2007.

B. T. McManus, Q.C.
Acting Chairman

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Introduction

Purpose

Directive 017 consolidates, clarifies, and updates Alberta Energy and Utilities Board (EUB) requirements related to the measurement of fluid (gas and liquid) production and disposition associated with upstream petroleum operations. The term "measurement" as used in this document means "measurement, accounting, and reporting." While measurement is the determination of a volume, accounting and reporting are integral components of measurement in that after a fluid volume is "measured," mathematical procedures (accounting) may have to be employed to arrive at the desired volume to be "reported."

Intent

This directive specifies
- what and how volumes must be measured ,
- what, where, and how volumes may be estimated,
- if accounting procedures must be performed on the determined volumes and what they are,
- what data must be kept for audit purposes, and
- what resultant volumes must be reported to the EUB.

The licensee must comply with all requirements set out in this directive.

In this directive, the term "must" indicates a requirement that must be followed. In some situations, a requirement may be subject to exceptions if specific conditions are met.

The term "should" indicates a recommendation that will not be subject to enforcement. However, the EUB may direct the licensee in writing to implement changes to improve measurement accuracy, and this direction will become a condition of operation for that facility or facilities.

The directive does not include instructions on how the volumes must be reported to the EUB; that is included in other EUB documents, such as *Directive 007: Production Accounting Handbook.*

Note that other sections relating to measurement listed in Appendix 1 are under development and will be added to the directive as they are completed.

If requirements in previously issued EUB documents (interim directives, informational letters, guides, etc.) conflict with the requirements in this directive, the requirements in this directive replace the prior requirements. Over time, it is intended that all relevant superseded requirements will be rescinded.

EUB documents fully or partially replaced by this directive are listed in the Appendix 2.

Definitions

Many terms used in this directive are defined in the Glossary (Appendix 3). However, many critically important definitions are also included within applicable sections.

Enforcement

This directive does not currently include a specific section on enforcement. This section will be developed and added once all the other sections have been completed.

1 Standards of Accuracy

1.1 Introduction

With regard to accuracy, it is assumed an exact or true value exists for any variable that is valid for the conditions existing at the moment the result is determined. Determining the true value without doubt cannot be done, due to the limitations of measuring equipment and procedures and the possibility of human error. Typically, the closer one wants to approach the true value, the more expense and efforts have to be expended.

The EUB has developed standards of accuracy for gas and liquid measurement that take into account such concerns as royalty, equity, reservoir engineering, declining production rates, and aging equipment. These standards have evolved, but originated from a 1972 Board hearing decision that determined a need for pool production accuracy standards of 2% for oil, 3% for gas, and 5% for water. The current standards are stated as "maximum uncertainty of monthly volume" and/or "single point measurement uncertainty." The uncertainties are to be applied as "plus/minus" (e.g., ±5%). Measurement at delivery/sales points must meet the highest accuracy standards because volumes determined at these points have a direct impact on royalty determination. Other measurement points that play a role in the overall accounting process are subject to less stringent accuracy standards to accommodate physical limitations and/or economics.

The specific standards of accuracy are listed in Section 1.8.

1.2 Applicability and Use of Uncertainties

The EUB used the uncertainty levels contained in this section to develop many of the requirements for equipment and/or procedures relating to measurement, accounting, and reporting for various aspects of oil and gas production and processing operations, which are explained in detail in other sections. **If those requirements are being met, the EUB considers a licensee to be in compliance without the need to demonstrate compliance with the applicable uncertainty requirements contained in this section. In other words, licensees need not have any concern about the stated uncertainty limits for operations that meet minimum requirements, exception requirements, or specific EUB approval requirements as set out in this directive. EUB inspectors and auditors do not look for compliance with the stated uncertainty limits in conducting inspections and audits.**

In some cases a licensee may wish to deviate from the minimum requirements for equipment and/or procedures that are stated in this guide. That may be acceptable if it is in accordance with the following:

- A licensee may deviate from the minimum requirements without specific EUB approval if no royalty, equity, or reservoir engineering concerns are associated with the volumes being measured and the licensee is able to demonstrate that the alternative measurement equipment and/or procedures will provide measurement accuracy within the applicable uncertainties. In some cases, as described in Section 5: Site-specific Deviation from Base Requirements, the licensee does not need to demonstrate compliance with the applicable uncertainties, but may instead demonstrate compliance with other specific criteria. In such cases, EUB inspectors and auditors will review the licensees' records for demonstrated compliance with the uncertainty limits or with the other specified criteria.
- If royalty, equity, or engineering concerns are associated with the volumes being measured, a licensee may be allowed, upon application to the Operations Group of the EUB's Compliance and Operations Branch, to deviate from the minimum requirements. The application must demonstrate that the proposed alternative measurement equipment

and/or procedures will either provide measurement accuracy within the applicable uncertainties or meet specific criteria described in Section 5: Site-specific Deviation from Base Requirements. Applications will also be considered if measurement accuracy will be marginally outside the uncertainty limits or specified criteria will be marginally exceeded. In such cases, EUB inspectors and auditors will review the licensees' records for documentation to confirm that approval has been obtained to deviate from the minimum requirements and for compliance with the approval conditions.

Note that crude bitumen wells and heavy oil wells (density of 920 kilograms per cubic metre [kg/m^3] or greater at 15°C) have specific measurement requirements that in some cases differ from those applicable to conventional oil wells. In those cases, the crude bitumen and heavy oil measurement requirements are based on operational characteristics and limitations, rather than uncertainty limits. The uncertainties described in this section do not apply to measurement of heavy oil production associated with the following oil systems:

- total battery gas
- well oil (proration battery)
- well gas (proration battery)
- well water (proration battery)

1.3 Maximum Uncertainty of Monthly Volume

The EUB requires production data to be reported on a calendar month basis. "Maximum uncertainty of monthly volume" relates to the limits applicable to equipment and/or procedures used to determine the total monthly volume. Total monthly volumes may result from a single month-long measurement, but more often result from a combination of individual measurements and/or estimations. For example, consider a well in an oil proration battery to which a maximum uncertainty of monthly volume would apply:

- First, the well is tested, and the oil test rate is used to estimate the well's production for the period until the next test is conducted.
- The well's total estimated oil production for the month is combined with the month's estimated oil production for the other wells in the battery to arrive at the total estimated monthly oil production for the battery.
- The total actual monthly oil production for the battery is determined based on measured deliveries out of the battery and inventory change.
- A proration factor is determined by dividing the actual battery production by the estimated battery production.
- The proration factor is multiplied by the well's estimated production to determine the well's actual monthly production.

1.4 Single Point Measurement Uncertainty

"Single point measurement uncertainty" relates to the limits applicable to equipment and/or procedures used to determine a single-phase specific volume at a single measurement point. The oil volume determined during a 24-hour well test conducted on a well in a proration battery is an example of a specific volume determination to which a single point measurement uncertainty limit would apply.

1.5 Confidence Level

The stated uncertainties are not absolute limits. The confidence level, which indicates the probability that true values will be within the stated range, is 95%. This implies that there is a 95% probability (or 19 chances in 20) that the true value will be within the stated range.

1.6 Determination of Uncertainties

The uncertainties referred to relate to the accuracies associated with measurement devices, device calibration, sample gathering and analysis, variable operating conditions, etc. These uncertainties are for single-phase specific volume determination points of specific fluids (oil, gas, or water) or for combinations of two or more such points. These uncertainties do not relate to comparisons of two or more measurement points, such as comparison of inlet volumes to outlet volumes. Such comparisons are typically expressed as proration factors, allocation factors, or metering differences.

The uncertainties are relevant to equipment at the time of installation. No uncertainty adjustment is required to account for the effects of multiphase fluids, wear, sludge or scale buildup, etc., as it is accepted that such conditions would constitute a bias error to be monitored and accounted for through the use of proration factors, allocation factors, or metering differences.

The methods to be used for determining and combining uncertainties are found in the latest edition of the American Petroleum Institute (API) *Manual of Petroleum Measurement Standards* (MPMS), Chapter 13: Statistical Aspects of Measuring and Sampling or the latest edition of the International Standard Organization (ISO) Standard 5168: Measurement of Fluid Flow—Estimation of Uncertainty of a Flow-rate Measurement.

1.6.1 Example Calculation

Determination of single point measurement uncertainty for well oil (proration battery) using "root sum square" methodology:

Individual uncertainties from historical EUB research:

For oil/emulsion measurement,
Oil meter uncertainty = 0.5% (typical manufacturer's specification)
Meter proving uncertainty = 1.5%
Basic sediments and water (BS&W) determination uncertainty = 0.5%
Combined uncertainty $= \sqrt{[(0.5)^2 + (1.5)^2 + (0.5)^2]}$
$= 1.66\%$ (rounded to 2.0%)

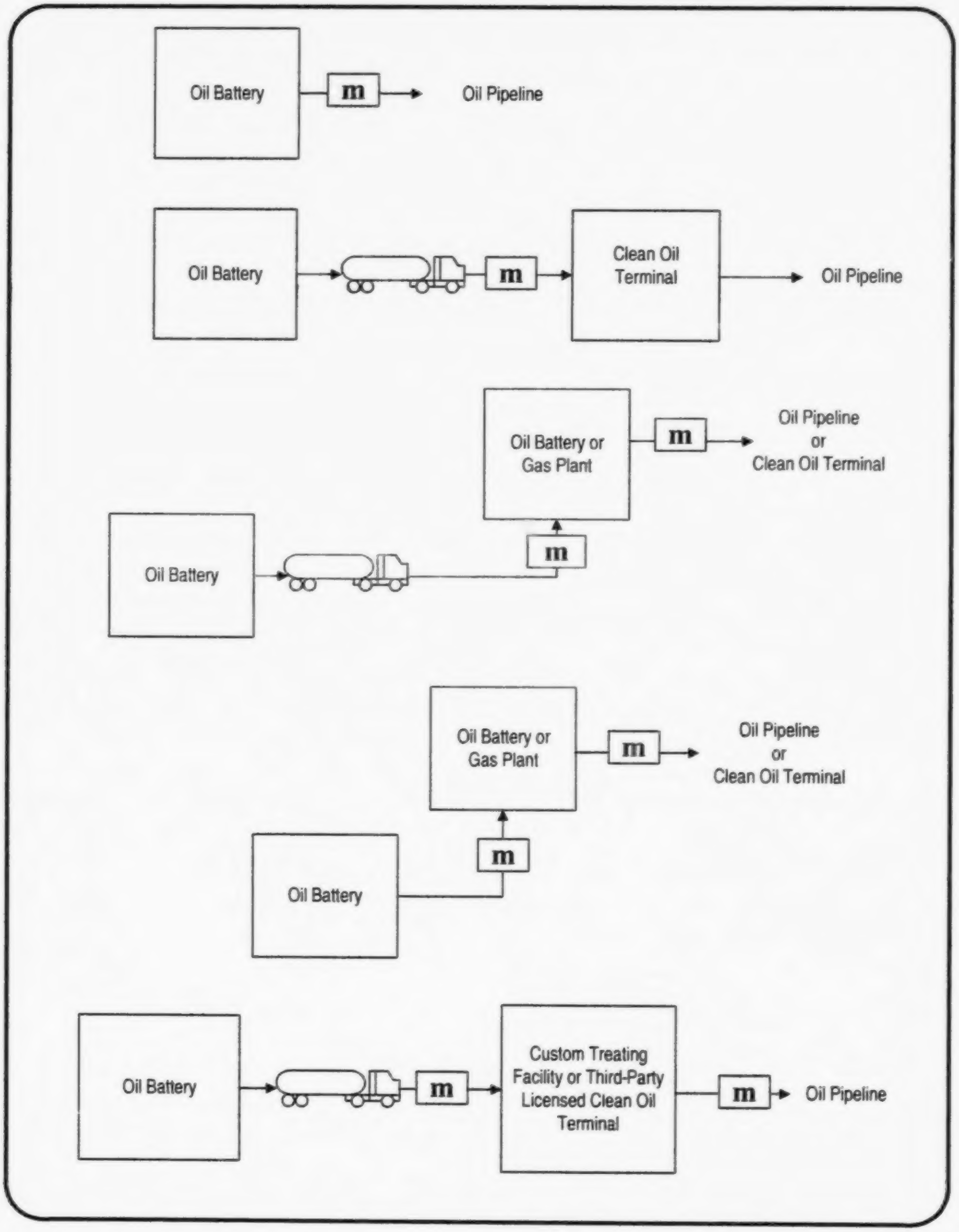
For delivery point gas measurement,
Primary measurement device – gas meter uncertainty = 1.0%
Secondary device – (pulse counter or transducer, etc.) uncertainty = 0.5%
Secondary device calibration uncertainty = 0.5%
Tertiary device – (flow calculation, EFM, etc.) uncertainty = 0.2%
Gas sampling and analysis uncertainty = 1.5%
Combined uncertainty $= \sqrt{[1.0)^2 + (0.5)^2 + (0.5)^2 + (0.2)^2 + (1.5)^2]}$
$= 1.95\%$ (rounded to 2.0%)

1.7 Explanation of Standards of Accuracy

1.7.1 Oil Systems

(i) **Total battery oil** (delivery point measurement), including single-well batteries

For Figure 1.1,
m = single point measurement uncertainty



Oil Battery
m
Oil Pipeline
Oil Battery
m
Clean Oil Terminal
Oil Pipeline
Oil Battery or Gas Plant
m
Oil Pipeline or Clean Oil Terminal
Oil Battery
m
Oil Battery or Gas Plant
m
Oil Pipeline or Clean Oil Terminal
Oil Battery
m
Oil Battery
m
Custom Treating Facility or Third-Party Licensed Clean Oil Terminal
m
Oil Pipeline

Figure 1.1

Maximum uncertainty of monthly volume = N/A
The uncertainty of the monthly volume will vary, depending upon the number of individual measurements that are combined to yield the total monthly volume.

Single point measurement uncertainty:
Delivery point measures > 100 m^3/d = 0.5%
Delivery point measures ≤ 100 m^3/d = 1%

The term "delivery point measurement" for crude oil refers to the point at which the oil production from a battery is measured. If clean oil is delivered directly into a pipeline system (Lease Automatic Custody Transfer [LACT] measurement) or trucked to a pipeline terminal, this point can also be referred to as the "custody transfer point." The "delivery point" terminology is from the perspective of the producing battery, but the receiving facility (pipeline, terminal, custom treating facility, other battery, etc.) may refer to this point as their "receipt point." The oil volume determined at the delivery point is used in all subsequent transactions involving the oil from the battery.

The measurement equipment and/or procedures must be capable of determining the oil volume within the stated uncertainties if clean oil is being measured.

If the oil volume delivered out of a battery is included in an oil/water emulsion, the stated uncertainties apply to the total emulsion volume determination only. It is accepted that potential errors associated with obtaining and analyzing a representative emulsion sample may prevent the oil volume from being determined within the stated uncertainties.

For facilities that receive oil volumes from other batteries totalling ≤ 100 m^3/d, the single point measurement uncertainty has been increased to allow for the economical handling of oil when minimal receipt volumes would not justify the added expense for improved measurement equipment and/or procedures.

(ii) **Total battery gas** (includes produced gas that is vented, flared, or used as fuel), including single-well batteries—also referred to as "associated gas," as it is the gas produced in association with oil production at oil wells

For Figure 1.2,
(**m**) = single point measurement uncertainty

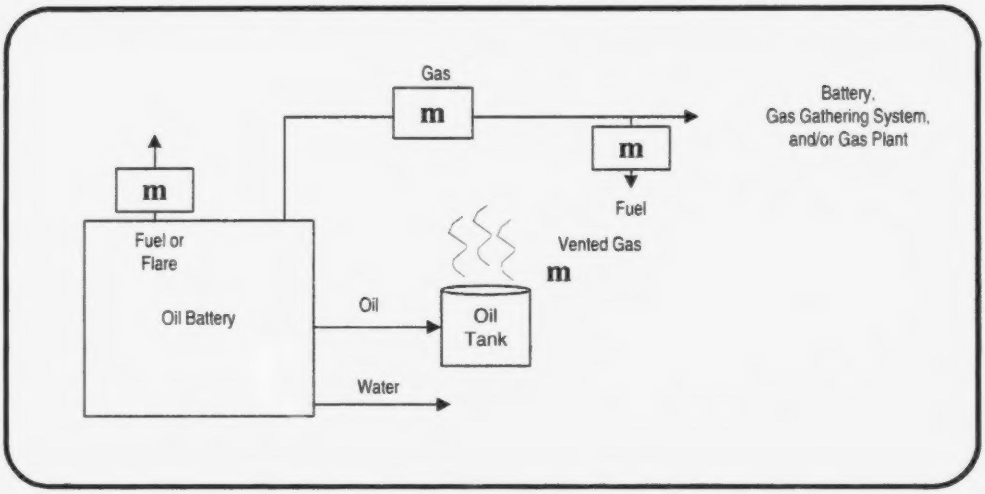


Figure 1.2

Single point measurement uncertainty:
$>16.9\ 10^3\ m^3/d = 3\%$
$> 0.50\ 10^3\ m^3/d$ but $\leq 16.9\ 10^3\ m^3/d = 3\%$
$\leq 0.50\ 10^3\ m^3/d = 10\%$

Maximum uncertainty of monthly volume (**M**)
$>16.9\ 10^3\ m^3/d = 5\%$
$> 0.50\ 10^3\ m^3/d$ but $\leq 16.9\ 10^3\ m^3/d = 10\%$
$\leq 0.50\ 10^3\ m^3/d = 20\%$
Note that **M** is dependent upon combined deliveries, fuel, and vented gas measurement.

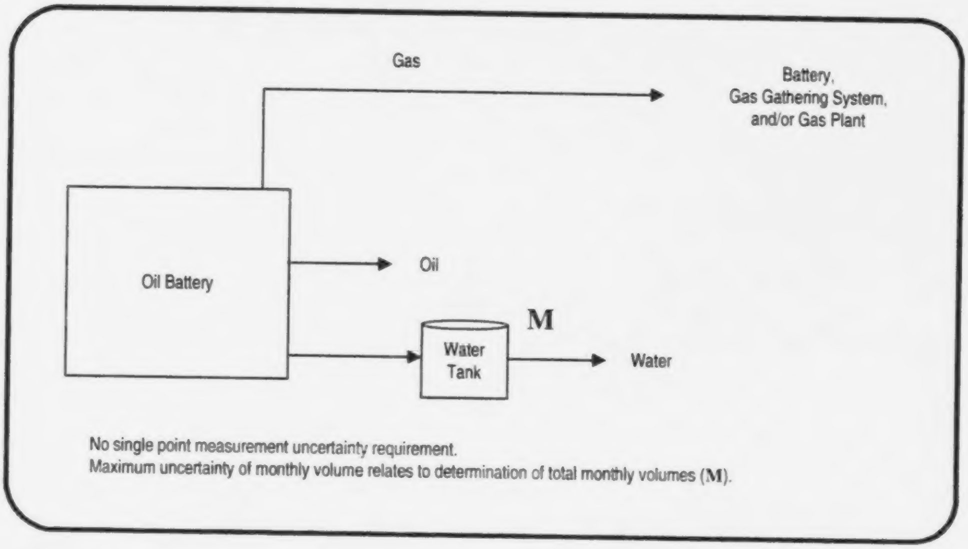
The maximum uncertainty of total monthly battery gas volumes allows for reduced emphasis on accuracy as gas production rate declines. For gas rates up to $0.50\ 10^3\ m^3/d$, the gas volumes may be determined by using estimates; therefore, the maximum uncertainty of monthly volume is set at 20%. If gas rates exceed $0.50\ 10^3\ m^3/d$, the gas must be measured; however, a component of the total monthly gas volume may include estimates for low volumes of fuel, vented, or flare gas that may add to the monthly uncertainty. At the highest gas production rates, it is expected the use of estimates will be minimal or at least have a minor impact on the accuracy of the total monthly gas volume, thereby resulting in the 5% maximum uncertainty of monthly volume.

The equipment and/or procedures used to determine the measured gas volumes (when measurement is required) must be capable of meeting a 3% single point measurement uncertainty. Due to the difficulty associated with measuring very low gas rates, the equipment and/or procedures used in determining gas-oil ratios or other factors to be used in estimating gas volumes where rates do not exceed $0.50\ 10^3\ m^3/d$ are expected to be capable of meeting a 10% single point measurement uncertainty.

These uncertainties do not apply to gas produced in association with heavy oil (density of 920 kg/m^3 or greater at 15°C).

(iii) Total battery water, including single-well batteries

For Figure 1.3,
M = maximum uncertainty of monthly volume



No single point measurement uncertainty requirement.
Maximum uncertainty of monthly volume relates to determination of total monthly volumes (**M**).

Figure 1.3

Maximum uncertainty of monthly volume:
>50 m^3/month = 5%
≤ 50 m^3/month = 20%

Single point measurement uncertainty = N/A
Total battery water may be determined by measurement or estimation, depending on production rates, so no basic requirement has been set for single point measurement uncertainty.

Total battery water production volumes not exceeding 50 m^3/month may be determined by estimation; therefore, the maximum uncertainty of monthly volume is set at 20%.

If the total battery water production volumes exceed 50 m^3/month, the water must be separated from the oil and measured; therefore, the maximum uncertainty of monthly volume is set at 5%.

(iv) Well oil (proration battery)

For Figure 1.4,
(**m**) = single point measurement uncertainty

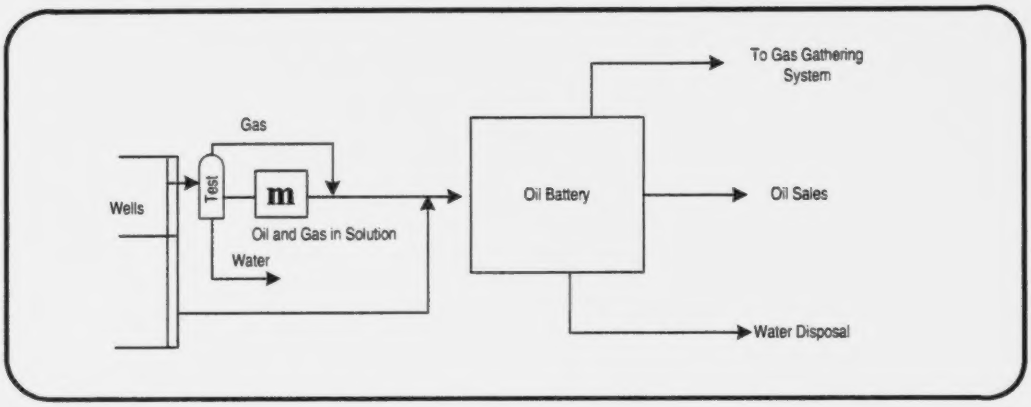


Figure 1.4

Single point measurement uncertainty:
All classes = 2%

Maximum uncertainty of monthly volume (**M**):
Class 1 (high) > 30 m^3/d = 5%
Class 2 (medium) > 6 m^3/d but ≤ 30 m^3/d = 10%
Class 3 (low) > 2 m^3/d but ≤ 6 m^3/d = 20%
Class 4 (stripper) ≤ 2 m^3/d = 40%
M is dependent upon oil and gas test volumes and the number of days the test is used for estimating production, plus correction by a proration factor.

The maximum uncertainty of monthly well oil production volumes for light and medium density oil wells in proration batteries has been developed to allow for reduced emphasis on accuracy as oil production rates decline. Rather than being determined by continuous measurement, monthly well oil production volumes are estimated from well tests and corrected by the use of proration factors to result in "actual" volumes. Lower rate wells are allowed reduced testing frequencies, which, coupled with the fact that wells may exhibit erratic production rates between tests, results in less certainty that the reported monthly oil production volume will be accurate.

The equipment and/or procedures used to determine oil volumes during the well tests must be capable of meeting a 2% single point measurement uncertainty for all classes of wells.

These uncertainties do not apply to heavy oil wells (density of 920 kg/m^3 or greater at 15°C) in proration batteries.

(v) **Well gas (proration battery)**—also referred to as "associated gas," as it is the gas produced in association with oil production at oil wells

For Figure 1.5,
(m) = single point measurement uncertainty

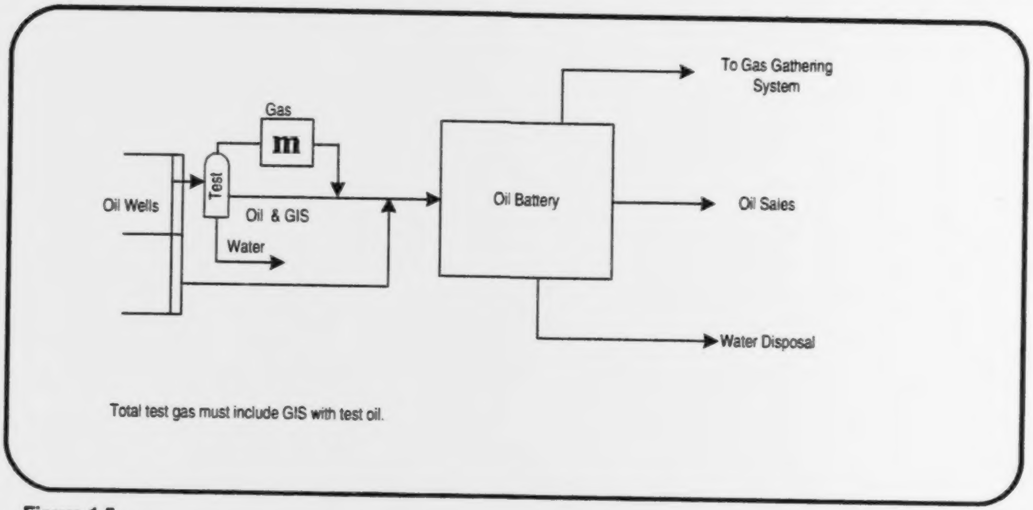


Figure 1.5

Single point measurement uncertainty:
$>16.9\ 10^3\ m^3/d = 3\%$
$> 0.50\ 10^3\ m^3/d$ but $\leq 16.9\ 10^3\ m^3/d = 3\%$
$\leq 0.50\ 10^3\ m^3/d = 10\%$

Maximum uncertainty of monthly volume (**M**):
$>16.9\ 10^3\ m^3/d = 5\%$
$> 0.50\ 10^3\ m^3/d$ but $\leq 16.9\ 10^3\ m^3/d = 10\%$
$\leq 0.50\ 10^3\ m^3/d = 20\%$

M is dependent upon oil and gas test volumes and the number of days the test is used for estimating production, plus correction by a proration factor.

The maximum uncertainty of monthly oil well gas volumes has been developed to allow for reduced emphasis on accuracy as gas production rates decline. Rather than being determined by continuous measurement, monthly oil well gas production volumes are estimated from well tests and corrected by the use of proration factors to result in "actual" volumes. Low gas production rates are typically associated with wells that are allowed reduced testing frequencies, which, coupled with the fact that wells may exhibit erratic production rates between tests, results in less certainty that the reported monthly gas production volume will be accurate.

For gas rates up to $0.50\ 10^3\ m^3/d$, the well test gas volume may be determined by using estimates; therefore, the maximum uncertainty of monthly volume is set at 20%. If gas rates exceed $0.50\ 10^3\ m^3/d$, the test gas must be measured; however, a component of a well's total test gas volume may include estimates for solution gas dissolved in the test oil volume (gas-in-solution), which may add to the monthly uncertainty. At the highest gas production rates, it is expected that the use of estimates will be minimal or at least have a minor impact on the accuracy of the total monthly gas volume, thereby resulting in the 5% maximum uncertainty of monthly volume.

The equipment and/or procedures used to determine the measured test gas volumes (if measurement is required) must be capable of meeting a 3% single point measurement uncertainty. Due to the difficulty associated with measuring very low gas rates, the equipment and/or procedures used in determining gas-oil ratios or other factors to be used in estimating gas volumes if rates do not exceed 0.50 10^3 m^3/d are expected to be capable of meeting a 10% single point measurement uncertainty.

These uncertainties do not apply to gas produced by heavy oil wells (density of 920 kg/m^3 or greater at 15°C) in proration batteries.

(vi) Well water (proration battery)

For Figure 1.6,
(m) = single point measurement uncertainty

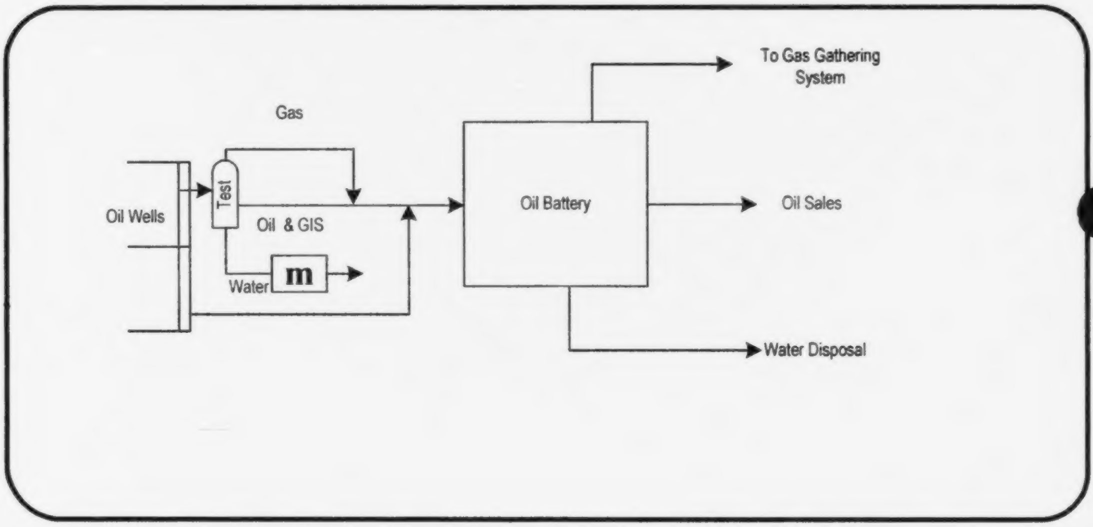


Figure 1.6

Single point measurement uncertainty = 10%

Maximum uncertainty of monthly volume = N/A
The uncertainty of the monthly volume will vary, depending upon the method used to determine test water rates and the frequency of well tests.

Rather than being determined by continuous measurement, monthly oil well water production volumes are estimated from well tests and corrected by the use of proration factors to result in "actual" volumes. The water rates determined during the well tests may be inferred from determining the water content of emulsion samples, and in some cases estimates may be used to determine water rates. Therefore, the single point measurement uncertainty is set at 10%.

These uncertainties do not apply to heavy oil wells (density of 920 kg/m^3 or greater at 15°C) in proration batteries.

1.7.2 Gas Systems

(i) Gas deliveries (sales gas)

For Figure 1.7,
(**m**) = single point measurement uncertainty

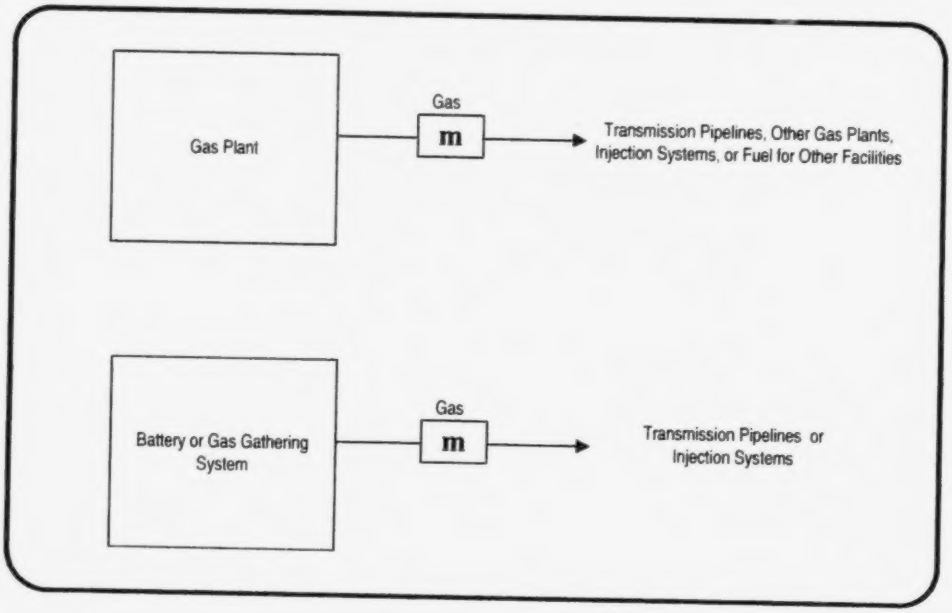

Gas Plant
Gas
m
Transmission Pipelines, Other Gas Plants, Injection Systems, or Fuel for Other Facilities
Battery or Gas Gathering System
Gas
m
Transmission Pipelines or Injection Systems

Figure 1.7

Single point measurement uncertainty = 2%

Maximum uncertainty of monthly volume = N/A
The total monthly volume may result from a single month-long measurement, making the uncertainty of the monthly volume equivalent to the single point measurement uncertainty.

Gas deliveries in this context will typically be clean, processed sales gas that is delivered out of a gas plant into a transmission pipeline. The measurement at this point determines the gas volumes upon which royalties will be based. Therefore, a stringent expectation is set for the single point measurement uncertainty. In some cases, this type of gas may be delivered to other plants for further processing or to injection facilities.

(ii) Hydrocarbon liquid deliveries

For Figure 1.8,
(**m**) = single point measurement uncertainty

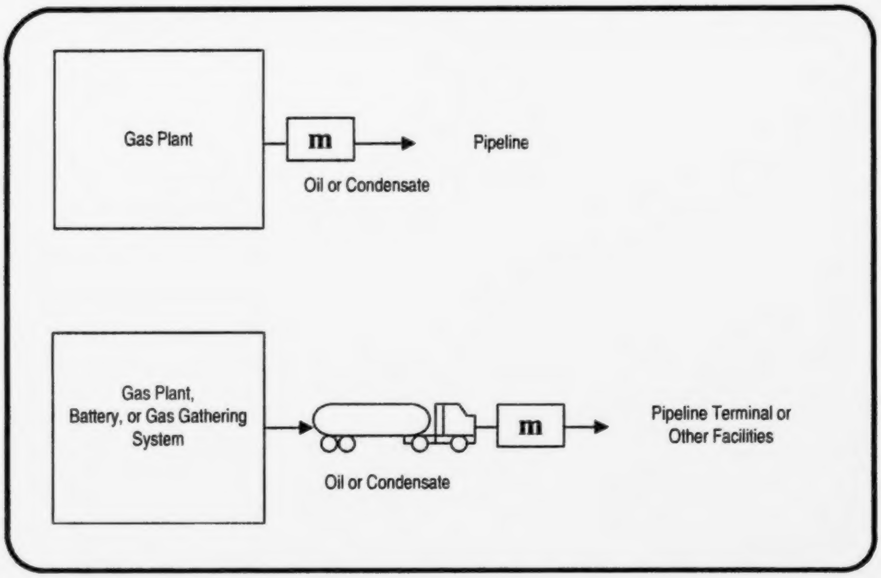

Gas Plant
m
Pipeline
Oil or Condensate
Gas Plant, Battery, or Gas Gathering System
m
Pipeline Terminal or Other Facilities
Oil or Condensate

Figure 1.8

Single point measurement uncertainty:
Delivery point measures > 100 m^3/d = 0.5%
Delivery point measures ≤ 100 m^3/d = 1%

Maximum uncertainty of monthly volume = N/A
The uncertainty of the monthly volume will vary, depending upon the number of individual measurements that are combined to yield the total monthly volume.

The term "delivery point measurement" for hydrocarbon liquids refers to the point at which the hydrocarbon liquid production from a battery or facility is measured. Where clean hydrocarbon liquids are delivered directly into a pipeline system (Lease Automatic Custody Transfer [LACT] measurement) or trucked to a pipeline terminal, it can also be referred to as the "custody transfer point." The "delivery point" terminology is from the perspective of the producing battery or facility, but the receiving facility (pipeline, terminal, custom treating facility, other battery, etc.) may refer to this point as its "receipt point." The hydrocarbon liquid volume determined at the delivery point is used in all subsequent transactions involving that liquid.

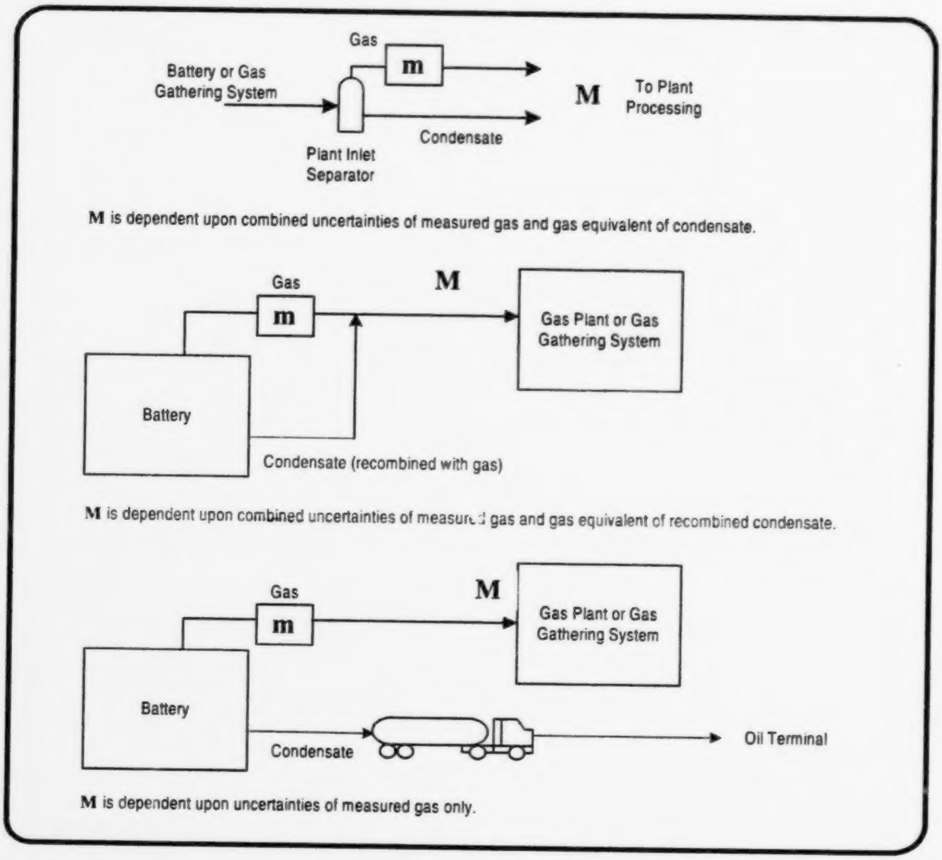
Hydrocarbon liquids delivered out of a gas system at the well, battery, or plant inlet level are typically condensate, and in some cases they may be considered to be oil. The hydrocarbon liquids delivered out of a gas plant may be pentanes plus, butane, propane, ethane, or a mixture of various components. The volumes determined at this point are the volumes upon which royalties are based.

The measurement equipment and/or procedures must be capable of determining the hydrocarbon liquid volume within the stated limits.

For facilities where the hydrocarbon liquid delivery volumes total ≤ 100 m^3/d, the single point measurement uncertainty has been increased to allow for the economical handling of hydrocarbon liquids when minimal volumes would not justify the added expense for improved measurement equipment and/or procedures.

(iii) Plant inlet or total battery/group gas

For Figure 1.9,
M = maximum uncertainty of monthly volume
(**m**) = single point measurement uncertainty


Gas
m
Battery or Gas Gathering System
M
To Plant Processing
Condensate
Plant Inlet Separator
Gas
m
M
Gas Plant or Gas Gathering System
Battery
Condensate (recombined with gas)
Gas
m
M
Gas Plant or Gas Gathering System
Battery
Condensate
Oil Terminal

M is dependent upon combined uncertainties of measured gas and gas equivalent of condensate.

M is dependent upon combined uncertainties of measured gas and gas equivalent of recombined condensate.

M is dependent upon uncertainties of measured gas only.

Figure 1.9

Maximum uncertainty of monthly volume = 5%

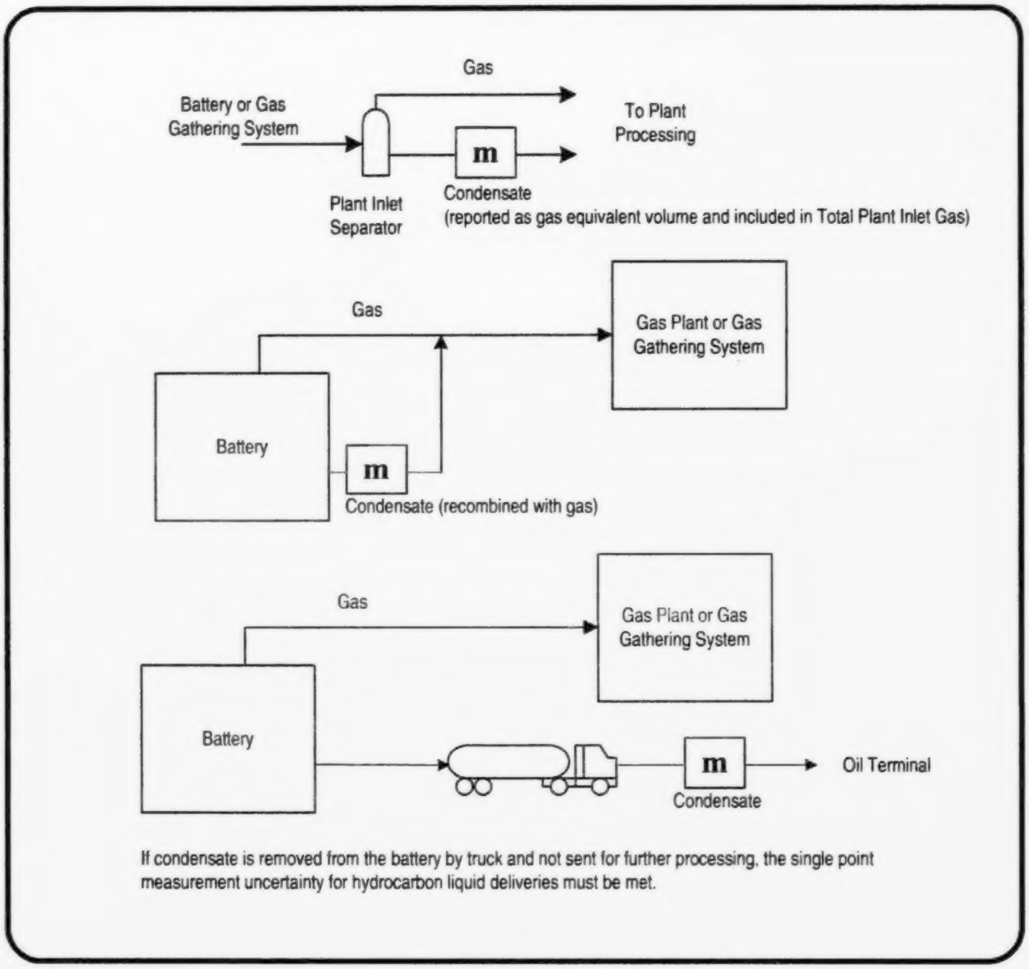
Single point measurement uncertainty = 3%

Plant inlet gas or total battery/group gas is typically unprocessed gas that may vary in composition and may contain entrained liquids. The total reported gas volume could result from combining several measured volumes from various points and may also include the calculated gas equivalent volume of entrained hydrocarbon liquids (typically condensate). The expectation for the maximum uncertainty of monthly volume is set at 5% to allow for the uncertainties associated with measuring gas under those conditions.

The equipment and/or procedures used to determine the measured gas volumes must be capable of meeting a 3% single point measurement uncertainty.

(iv) Plant inlet or total battery/group condensate (recombined)

For Figure 1.10,
(**m**) = single point measurement uncertainty


Gas
Battery or Gas Gathering System
To Plant Processing
m
Plant Inlet Separator
Condensate
(reported as gas equivalent volume and included in Total Plant Inlet Gas)
Gas
Gas Plant or Gas Gathering System
Battery
m
Condensate (recombined with gas)
Gas
Gas Plant or Gas Gathering System
Battery
m
Oil Terminal
Condensate

If condensate is removed from the battery by truck and not sent for further processing, the single point measurement uncertainty for hydrocarbon liquid deliveries must be met.

Figure 1.10

Single point measurement uncertainty = 2%

Maximum uncertainty of monthly volume = N/A
The condensate volume is included in the total gas volume for reporting purposes and is therefore covered by the maximum uncertainty of monthly volume for the plant inlet or total battery/group gas.

Plant inlet condensate is typically separated from the inlet stream and sent through the plant for further processing. For reporting purposes, the gas equivalent of the plant inlet condensate is included in the total plant inlet gas volume. If total battery/group condensate upstream of the plant inlet is separated and measured prior to being recombined with the gas production, the condensate is converted to a gas equivalent volume and included in the gas production volume. In either case, the condensate single point measurement uncertainty is set at 2% for the liquid volume determination.

Note that if plant inlet or total battery/group condensate is separated and delivered out of the system at that point, the condensate measurement is subject to the single point measurement uncertainties stipulated for hydrocarbon liquid deliveries (above).

(v) Fuel gas

For Figure 1.11,
(**m**) = single point measurement uncertainty

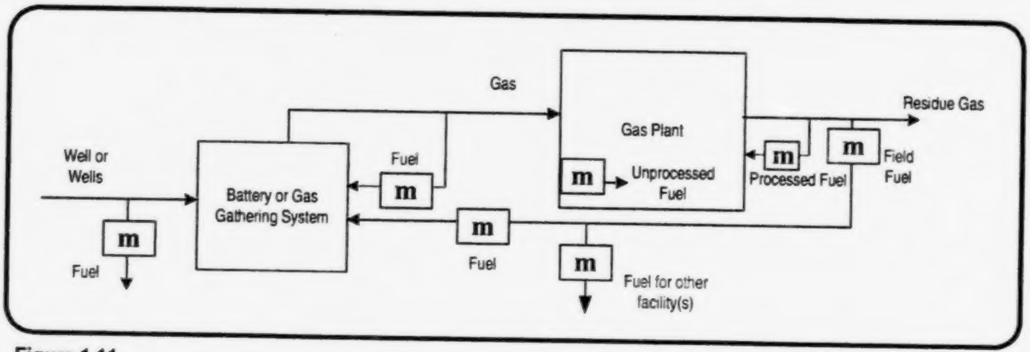


Figure 1.11

Single point measurement uncertainty:
$> 0.50\ 10^3\ m^3/d = 3\%$
$\leq 0.50\ 10^3\ m^3/d = 10\%$

Maximum uncertainty of monthly volume (**M**):
$> 0.50\ 10^3\ m^3/d = 5\%$
$\leq 0.50\ 10^3\ m^3/d = 20\%$

Note that **M** is dependent upon combined uncertainties of various fuel sources at each reporting facility.

The maximum uncertainty of monthly fuel gas volumes allow for reduced emphasis on accuracy as gas flow rates decline. For annual average fuel gas rates up to $0.50\ 10^3\ m^3/d$ on a per-site basis, the gas volume may be determined by using estimates; therefore, the maximum uncertainty of the monthly volume is set at 20%. If the annual average fuel gas rates exceed $0.50\ 10^3\ m^3/d$ on any site, the gas must be measured, but since the gas being used as fuel may be unprocessed gas and part of the total fuel gas volume may include some estimated volumes (up to $0.50\ 10^3\ m^3/d$), the maximum uncertainty of the monthly volume is set at 5% to allow for the uncertainties associated with measuring gas under those conditions.

The equipment and/or procedures used to determine the measured gas volumes (if measurement is required) must be capable of meeting a 3% single point measurement uncertainty. Due to the difficulty associated with measuring very low gas rates, the equipment and/or procedures used in determining gas-oil ratios or other factors to be used in estimating gas volumes if rates do not exceed 0.50 10^3 m^3/d are expected to be capable of meeting a 10% single point measurement uncertainty.

(vi) Flare gas

For Figure 1.12,
M = maximum uncertainty of monthly volume
(**m**) = single point measurement uncertainty

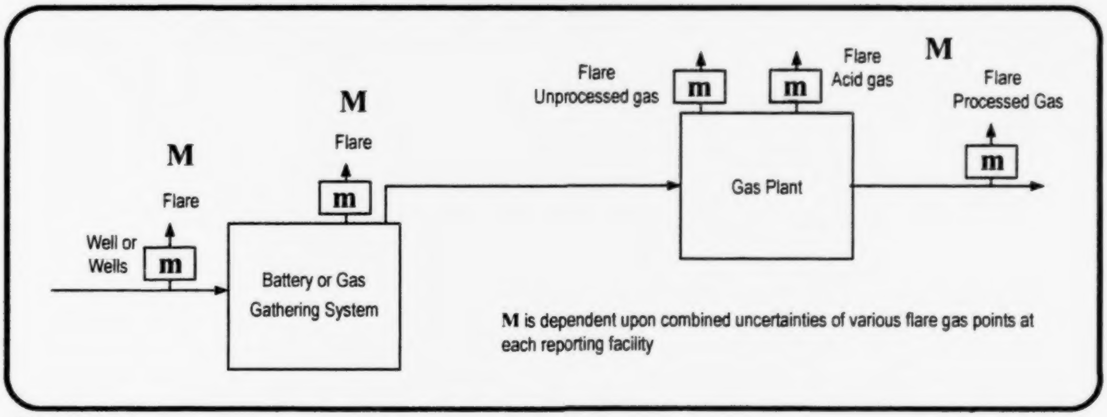

M
Flare
Well or Wells
m
Battery or Gas Gathering System
M
Flare
m
Flare Unprocessed gas
m
m
Flare Acid gas
Gas Plant
M
Flare Processed Gas
m
M is dependent upon combined uncertainties of various flare gas points at each reporting facility

Figure 1.12

Maximum uncertainty of monthly volume = 20%

Single point measurement uncertainty = 5%

Flare gas may be clean processed gas or it may be unprocessed gas, depending on the point in the system from which gas is being flared. Continuous or intermittent flare and vent sources at all oil and gas production and processing facilities (excluding heavy oil and crude bitumen) where annual average total flared and vented volumes per facility exceed 0.5 10^3 m^3/d (excluding pilot, purge, or dilution gas) must be measured. Flare lines usually operate in a shut-in condition and may be required to accommodate partial or full volumes of gas production during flaring conditions. In some cases if flaring is infrequent and no measurement equipment is in place, flare volumes must be estimated (such as flaring at southeastern Alberta gas wells in a proration battery where there is no on-site measurement equipment). Therefore, the maximum uncertainty of the monthly volume is set at 20%, to allow for the erratic conditions associated with flare measurement.

The equipment and/or procedures used to determine the measured gas volumes (if measurement, not an estimate, is required) must be capable of meeting a 5% single point measurement uncertainty.

(vii) Acid gas

For Figure 1.13,
(m) = single point measurement uncertainty

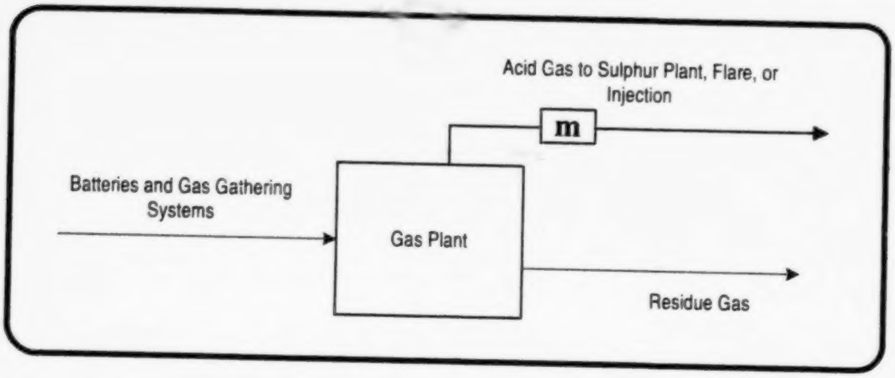

Acid Gas to Sulphur Plant, Flare, or Injection
m
Batteries and Gas Gathering Systems
Gas Plant
Residue Gas

Figure 1.13

Single point measurement uncertainty = 10%

Maximum uncertainty of monthly volume = N/A
The total monthly volume may result from a single month-long measurement, making the uncertainty of the monthly volume equivalent to the single point measurement uncertainty.

Acid gas usually contains a great deal of water vapour and has other conditions associated with it, such as very low pressure that affects measurement accuracy. Therefore, the single point measurement uncertainty is set at 10%.

(viii) Dilution gas

For Figure 1.14,
M = maximum uncertainty of monthly volume
(m) = single point measurement uncertainty

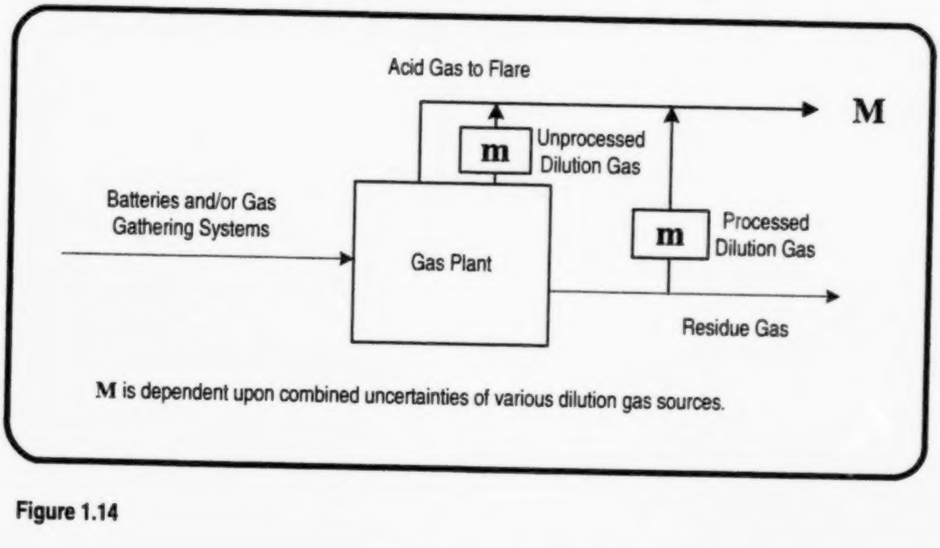

Acid Gas to Flare
M
m
Unprocessed Dilution Gas
Batteries and/or Gas Gathering Systems
Gas Plant
m
Processed Dilution Gas
Residue Gas
M is dependent upon combined uncertainties of various dilution gas sources.

Figure 1.14

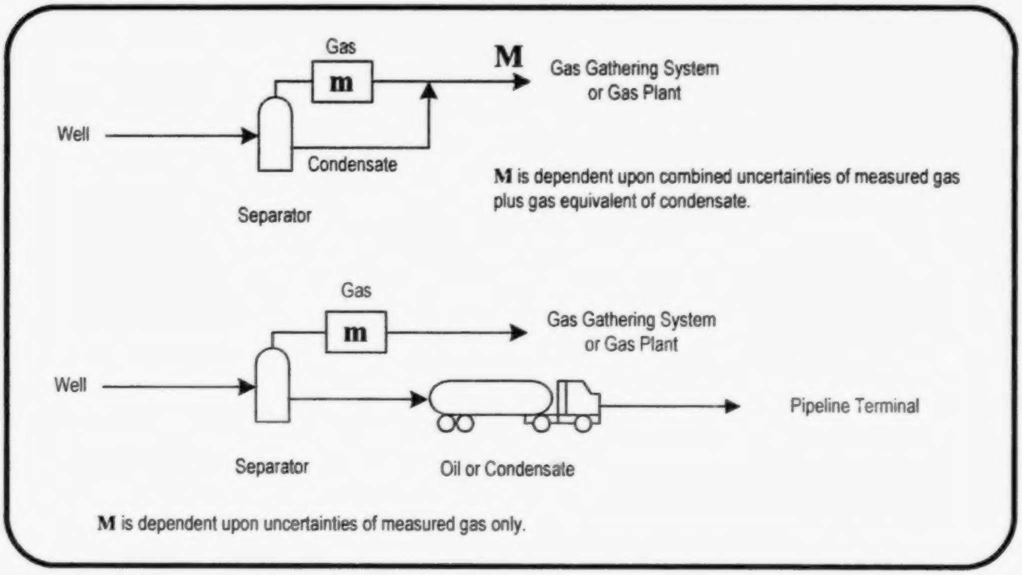
Maximum uncertainty of monthly volume = 5%

Single point measurement uncertainty = 3%

Dilution gas is typically "fuel" gas used to provide adequate fuel for incineration or flaring of acid gas. Since it must be measured, it is subject to the same uncertainties as stated above for fuel gas that must be determined by measurement.

(ix) Well gas (well site separation)

For Figure 1.15,
M = maximum uncertainty of monthly volume
(**m**) = single point measurement uncertainty



M is dependent upon combined uncertainties of measured gas plus gas equivalent of condensate.

M is dependent upon uncertainties of measured gas only.

Figure 1.15

Maximum uncertainty of monthly volume:
>16.9 10^3 m^3/d = 5%
≤16.9 10^3 m^3/d = 10%

Single point measurement uncertainty = 3%

If production components from gas wells are separated and continuously measured, the maximum uncertainty of monthly well gas volumes allows for reduced emphasis on accuracy as gas production rates decline. Since the separated gas is unprocessed and may still contain entrained liquids at the measurement point and a component of the total reported well gas production may include the calculated gas equivalent volume of the well's condensate production, the maximum uncertainty of monthly volumes also allows for the uncertainties associated with measuring gas under those conditions.

The equipment and/or procedures used to determine the separated measured well gas volumes must be capable of meeting a 3% single point measurement uncertainty.

(x) Well gas (proration battery)

For Figures 1.16 and 1.17,
M = maximum uncertainty of monthly volume
(**m**) = single point measurement uncertainty

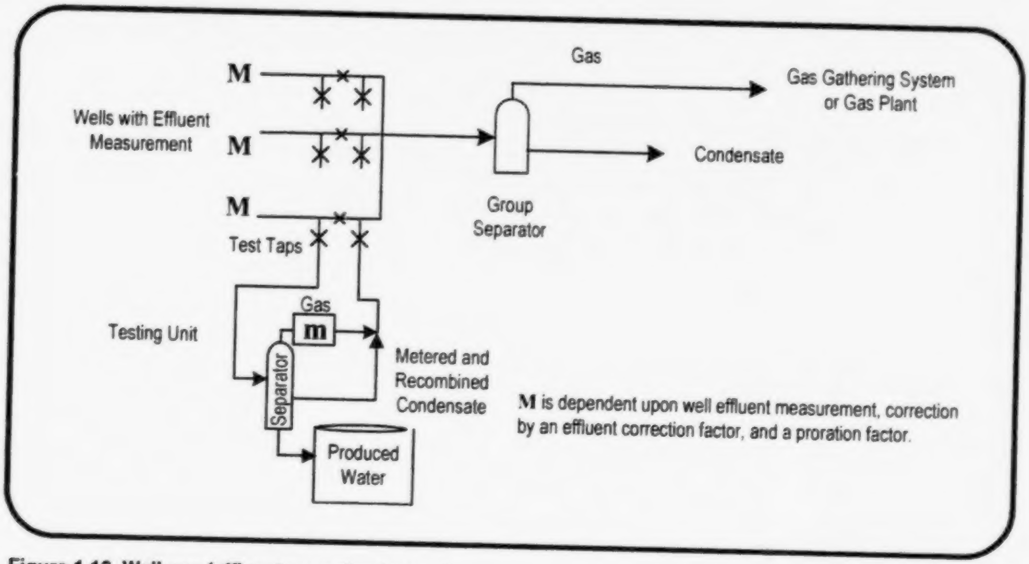

M
M
M
Wells with Effluent Measurement
Test Taps
Testing Unit
Gas
m
Separator
Produced Water
Metered and Recombined Condensate
Gas
Gas Gathering System or Gas Plant
Condensate
Group Separator
M is dependent upon well effluent measurement, correction by an effluent correction factor, and a proration factor.

Figure 1.16. Well gas (effluent proration battery)

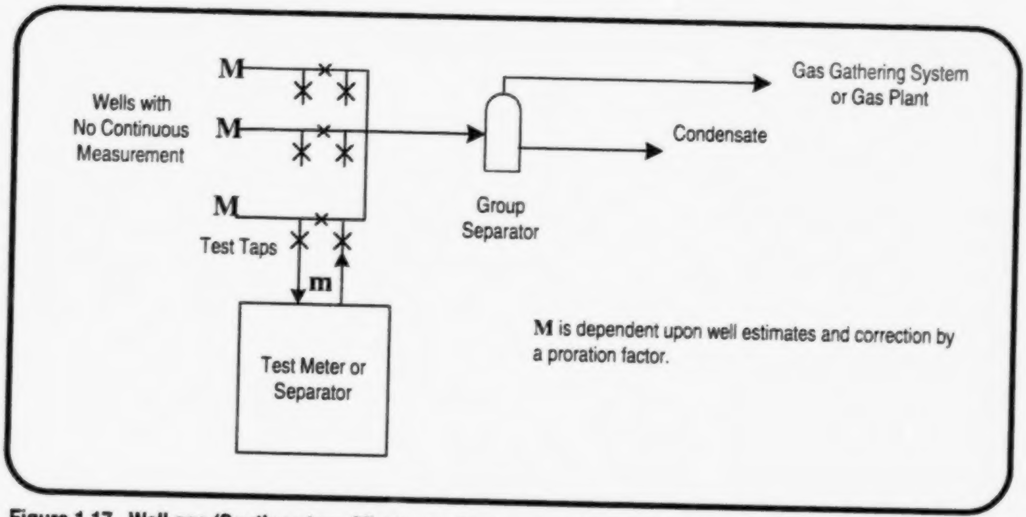

M
M
M
Wells with No Continuous Measurement
Test Taps
m
Test Meter or Separator
Gas Gathering System or Gas Plant
Condensate
Group Separator
M is dependent upon well estimates and correction by a proration factor.

Figure 1.17. Well gas (Southeastern Alberta or other approved proration battery)

Maximum uncertainty of monthly volume = 15%

Single point measurement uncertainty = 3%

If production components from gas wells are not separated and continuously measured, the gas wells are subject to a proration accounting system. There are two types of gas proration batteries. "Wet" gas wells have continuous effluent measurement, and the "actual" production is prorated based on the measurement of group gas and liquid components following separation at a central location. "Dry" gas wells approved to operate without continuous measurement have the production estimated based on periodic tests, and the actual production is prorated based on the measurement of group volumes at a central location. For both types of proration batteries, the maximum uncertainty of the monthly well gas volume is set at 15% to allow for the inaccuracies associated with these types of measurement systems.

The equipment and/or procedures used to determine the measured well test gas volumes downstream of separation during effluent meter correction factor tests or during the periodic dry gas well tests must be capable of meeting a 3% single point measurement uncertainty.

(xi) Well condensate (recombined)

For Figure 1.18,
(**m**) = single point measurement uncertainty

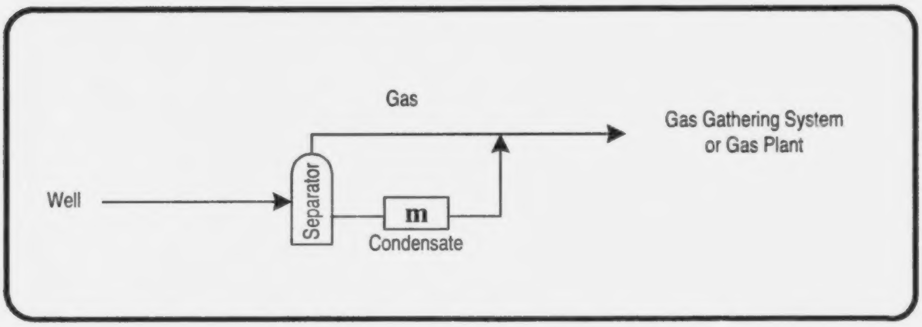


Figure 1.18

Single point measurement uncertainty = 2%

Maximum uncertainty of monthly volume = N/A
The gas equivalent of the condensate volume is included in the total well gas volume for reporting purposes and is therefore covered by the monthly uncertainty for the well gas.

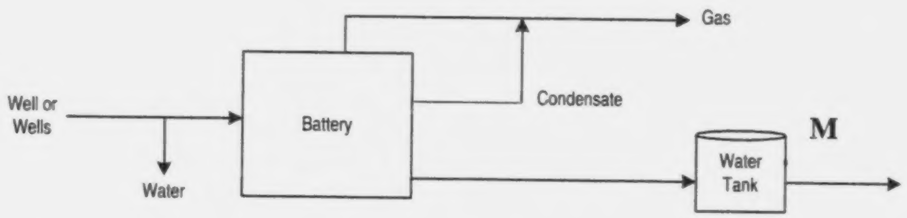
If condensate produced by a gas well is separated and measured at the wellhead prior to being recombined with the gas production, the condensate is mathematically converted to a gas equivalent volume and added to the well gas production volume. In this case, the condensate single point measurement uncertainty is set at 2% for the liquid volume determination. No requirement has been set for the maximum uncertainty of monthly volume because the gas equivalent of the condensate volume is included in the total well gas volume for reporting purposes.

In the case of a gas well subject to effluent measurement, the gas equivalent of the condensate volume is included in the well's total gas production volume. The liquid volume determination, which is done during the effluent meter correction factor test, is subject to a single point measurement uncertainty of 2%. No requirement has been set for the maximum uncertainty of monthly volume because the gas equivalent of the condensate volume is included in the total well gas volume for reporting purposes.

Note that if condensate produced by a gas well is separated at the wellhead and delivered out of the system at that point, the condensate is reported as a liquid volume. In this case, the condensate measurement is subject to the single point measurement uncertainties stipulated for hydrocarbon liquid deliveries (above).

(xii) Total battery water

For Figure 1.19,
M = maximum uncertainty of monthly volume



Total battery water may be the water separated at the battery, the sum of the water separated at the wells, or a combination. **M** is dependent upon the method used to determine the total water volume.

Figure 1.19

Maximum uncertainty of monthly volume = 5%

Single point measurement uncertainty = N/A
Total battery water may be determined by an individual group measurement, by totalling individual well measurements, or by totalling individual well estimates, so no basic requirement for measurement uncertainty has been set.

Total battery water in a gas system may be collected at a central location where it can be measured prior to disposal, or it may be a summation of individual well estimates or measurements of water collected at well sites and disposed from those sites. The 5% maximum uncertainty of monthly volume allows for some leeway in volume determination.

(xiii) Well water

For Figure 1.20,
(**m**) = single point measurement uncertainty

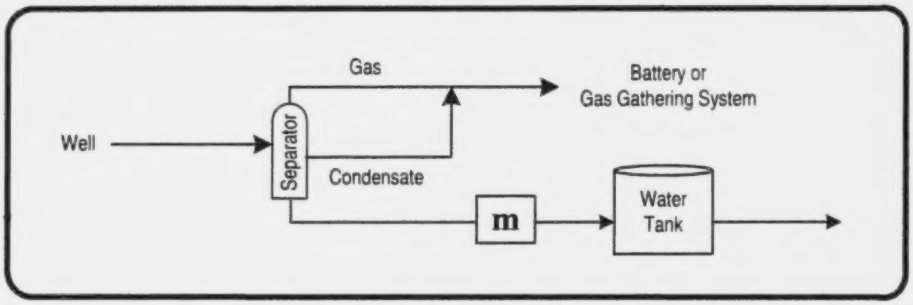

Gas
Battery or
Gas Gathering System
Well
Separator
Condensate
m
Water
Tank

Figure 1.20

Single point measurement uncertainty = 10%

Maximum uncertainty of monthly volume = N/A
The uncertainty of the monthly volume will vary, depending upon whether produced volumes are subject to individual well measurement, estimation, or proration.

Water production at gas wells may be determined by measurement after separation, or if separators are not used, it may be determined by using water-gas ratios determined from engineering calculations or semi-annual tests. To allow for the various methods used to determine production volumes, the single point measurement uncertainty is set at 10%.

1.7.3 Injection/Disposal Systems

(i) Total gas

For Figure 1.21,
M = maximum uncertainty of monthly volume

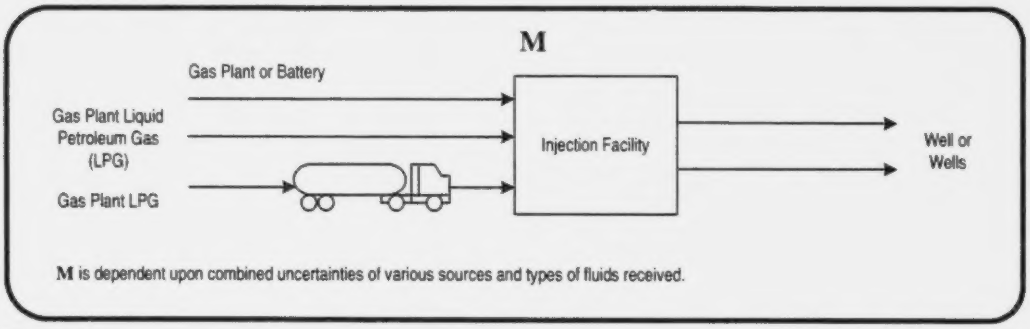

M
Gas Plant or Battery
Gas Plant Liquid
Petroleum Gas
(LPG)
Gas Plant LPG
Injection Facility
Well or
Wells
M is dependent upon combined uncertainties of various sources and types of fluids received.

Figure 1.21

Maximum uncertainty of monthly volume = 5%

Single point measurement uncertainty = N/A

The single point measurement uncertainty will vary depending on the source and type of fluids received.

Gas used in injection/disposal systems may be clean processed gas or unprocessed gas that may contain entrained liquids, and in some cases several sources may make up the total gas volume received by an injection system. The expectation for the maximum uncertainty of monthly volume is set at 5% to allow for the uncertainties associated with measuring gas under those conditions.

(ii) Well gas

For Figure 1.22,
(**m**) = single point measurement uncertainty

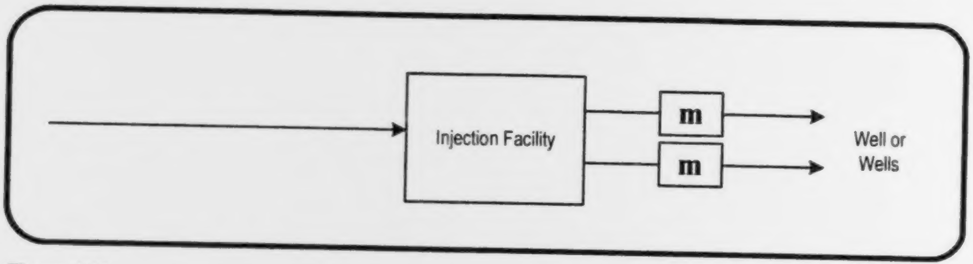

Injection Facility
m
m
Well or Wells

Figure 1.22

Single point measurement uncertainty = 3%

Maximum uncertainty of monthly volume = N/A
The total monthly volume may result from a single month-long measurement, making the uncertainty of the monthly volume equivalent to the single point measurement uncertainty.

The gas injected/disposed into wells must be measured and may consist of clean processed gas and/or unprocessed gas that may contain entrained liquids. The equipment and/or procedures used to determine the gas volumes injected/disposed into each well must be capable of meeting a 3% single point measurement uncertainty.

(iii) Total water

For Figure 1.23,
M = maximum uncertainty of monthly volume

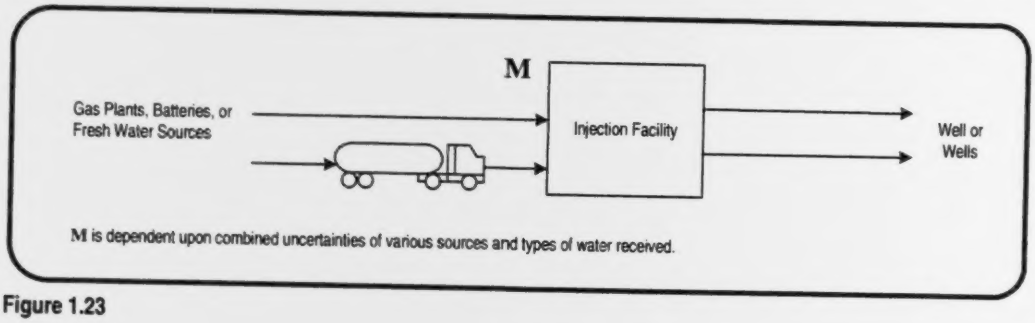

M
Gas Plants, Batteries, or Fresh Water Sources
Injection Facility
Well or Wells
M is dependent upon combined uncertainties of various sources and types of water received.

Figure 1.23

Maximum uncertainty of monthly volume = 5%

Single point measurement uncertainty = N/A
To be equivalent to the requirements for total oil and gas battery water.

Water used in injection/disposal systems may be produced water from oil or gas batteries, fresh water from water source wells, and/or waste water. To be equivalent to the requirements for total oil and gas battery water, the expectation for the maximum uncertainty of monthly volume is set at 5%.

(iv) Well water

For Figure 1.24,
(**m**) = single point measurement uncertainty

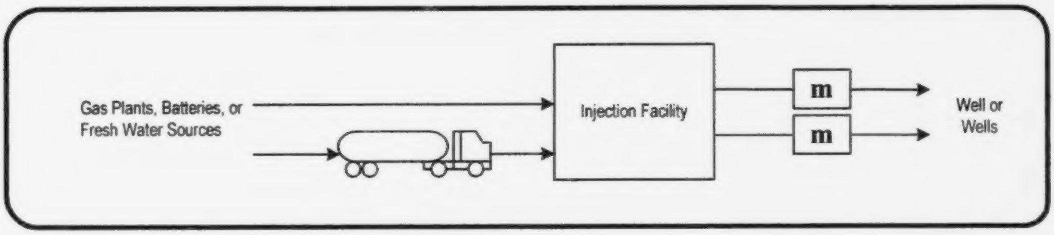


Figure 1.24

Single point measurement uncertainty = 5%

Maximum uncertainty of monthly volume = N/A
The total monthly volume may result from a single month-long measurement, making the uncertainty of the monthly volume equivalent to the single point measurement uncertainty.

The water injected/disposed into wells must be measured. The expectation for the single point measurement uncertainty is set at 5%.

1.8 Standards of Accuracy—Summary

1.8.1 Oil Systems

		Maximum uncertainty of monthly volume	Single point measurement uncertainty
(i)	Total battery oil (delivery point measurement)		
	Delivery point measures >100 m^3/d	N/A	0.5%
	Delivery point measures ≤ 100 m^3/d	N/A	1%
(ii)	Total battery gas (includes produced gas that is vented, flared, or used as fuel)		
	$> 16.9\ 10^3\ m^3/d$	5%	3%
	$> 0.50\ 10^3\ m^3/d$ but $\leq 16.9\ 10^3\ m^3/d$	10%	3%
	$\leq 0.50\ 10^3\ m^3/d$	20%	10%
(iii)	Total battery water		
	$> 50\ m^3$/month	5%	N/A
	$\leq 50\ m^3$/month	20%	N/A
(iv)	Well oil (proration battery)		
	Class 1 (high), $> 30\ m^3/d$	5%	2%
	Class 2 (medium), $> 6\ m^3/d$ but $\leq 30\ m^3/d$	10%	2%
	Class 3 (low), $> 2\ m^3/d$ but $\leq 6\ m^3/d$	20%	2%
	Class 4 (stripper), $\leq 2\ m^3/d$	40%	2%
(v)	Well gas (proration battery)		
	$> 16.9\ 10^3\ m^3/d$	5%	3%
	$> 0.50\ 10^3\ m^3/d$ but $\leq 16.9\ 10^3\ m^3/d$	10%	3%
	$\leq 0.50\ 10^3\ m^3/d$	20%	10%
(vi)	Well water	N/A	10%

1.8.2 Gas Systems

		Maximum uncertainty of monthly volume	Single point measurement uncertainty
(i)	Gas deliveries (sales gas)	N/A	2%
(ii)	Hydrocarbon liquid deliveries		
	Delivery point measures >100 m^3/d	N/A	0.5%
	Delivery point measures ≤100 m^3/d	N/A	1%
(iii)	Plant inlet or total battery/group gas	5%	3%
(iv)	Plant inlet or total battery/group condensate (recombined)	N/A	2%
(v)	Fuel gas		
	> 0.50 10^3 m^3/d	5%	3%
	≤ 0.50 10^3 m^3/d	20%	10%
(vi)	Flare gas	20%	5%
(vii)	Acid gas	N/A	10%
(viii)	Dilution gas	5%	3%
(ix)	Well gas (well site separation)		
	> 16.9 10^3 m^3/d	5%	3%
	≤ 16.9 10^3 m^3/d	10%	3%
(x)	Well gas (proration battery)	15%	3%
(xi)	Well condensate (recombined)	N/A	2%
(xii)	Total battery water	5%	N/A
(xiii)	Well water	N/A	10%

1.8.3 Injection Systems

		Maximum uncertainty of monthly volume	Single point measurement uncertainty
(i)	Total gas	5%	N/A
(ii)	Well gas	N/A	3%
(iii)	Total water	5%	N/A
(iv)	Well water	N/A	5%

2 Calibration and Proving

2.1 Definitions

For the purposes of this directive, calibration and proving have distinctly different meanings:

Calibration refers to procedures or operations that establish the accuracy of the values indicated by a measuring device as compared to the values indicated by a calibration instrument that has accuracy traceable to a suitable measuring standard. Adjustments are made, if required, to the measuring device to make it comparable to the calibration instrument. Calibration may also refer to the procedure used to determine the volume of a prover.

Proving refers to the procedures or operations whereby a prover volume is compared to an indicated meter volume (both corrected to applicable pressure and temperature conditions). The prover volume divided by the indicated meter volume yields a meter factor. The meter factor is subsequently applied to indicate meter volumes to determine the adjusted volume. If the meter is connected to an electronic readout, the meter factor may be incorporated into the software such that the indicated meter volume is already corrected to read the adjusted volume. (Care should be taken in such cases not to apply the meter factor again. In such cases, the meter factor should be indicated on the tag or label as being 1.0000.)

A **meter factor** is a dimensionless number used to correct indicated meter volumes to adjusted volumes if the two volumes differ due to operational conditions (e.g., gas entrained in liquids, meter slippage, meter wear). It is not to be confused with the "K Factor," which is the factor used to convert the number of pulses generated by a meter whose operation is based on electronic pulse technology into units of volume. The K Factor is typically determined by the meter manufacturer and does not take into consideration all of the specific operational conditions the meter may be subjected to.

Prover refers to a device used to collect and determine the volume of a sample of fluid that has passed through a meter. Provers typically use volumetric or gravimetric means to determine the quantity of the sample.

A **prover run** refers to the operation of a prover or master meter whereby a representative volume is sampled and measured, and that sample volume is compared to the volume indicated by a meter through which the same sample has passed to determine a meter factor.

Master meter refers to a meter of known accuracy that is connected in series with another meter for the purpose of checking the accuracy of the second meter and providing a meter factor.

A **measuring standard** refers to a device used in calibration or proving that has a known value that is traceable to national reference standards maintained by the National Research Council in Ottawa, Ontario.

2.2 Applicability

The calibration and proving requirements stipulated in this directive are applicable to measurement devices used in Alberta to determine volumes for EUB-required accounting and reporting purposes. These requirements are not applicable to measurement devices used only for a licensee's internal accounting purposes. The requirements are considered minimums, and a licensee may choose to apply more stringent requirements.

If a licensee wishes to deviate from these requirements or exceptions (other than applying more stringent requirements), see Section 1: Standards of Accuracy to determine if the deviation requires submission of an application to and approval by the EUB.

2.3 Frequency

The accuracy of measurement devices may deviate over time, due to wear, changes in operating conditions, changes in ambient conditions, etc. Generally, the more important the accuracy of a measurement device is, the more frequently it must be calibrated or proved.

For the purposes of this directive, calibration or proving frequency have the following meanings:

- Calendar quarters are January to March, April to June, July to September, and October to December.
- Monthly means at least once per calendar month.
- Bi-monthly means at least once every two calendar months.
- Quarterly means at least once per calendar quarter.
- Semi-annually means at least once every two calendar quarters.
- Annually means at least once every four calendar quarters.
- Bi-annually means at least once every eight calendar quarters (once every two years).
- Tri-annually means at least once every twelve calendar quarters (once every three years).

Example: For an annual frequency, if the last calibration was performed in May 2006, the operator has to perform another calibration by the end of June 2007 (end of the calendar quarter).

Exceptions

1) If the use or operation of a measurement device requiring monthly or quarterly calibration/proving is suspended for a significant period (at least seven consecutive days), the scheduled calibration/proving may be delayed by the number of days the device was not in use. Documentation of the amount of time the device was not in service must be kept and made available to the EUB on request. If this exception is being applied, the licensee must attach a tag to the meter indicating that this exception is in effect and the next scheduled calibration/proving date. This exception is not applicable to measurement devices subject to calibration/proving frequencies that are semi-annual or longer.

2) If a liquid meter is removed from service for bench proving but is put "on the shelf" and not returned to service for a considerable period of time, the countdown to the next required bench proving does not start until the meter is returned to service. The licensee must attach a tag to the meter indicating the installation date, but leaving the original proving tag intact.

3) The EUB may request that calibration/proving of a meter be done at any time or may extend the due date for scheduled calibration/proving, depending on the specific circumstances at a measurement point.

2.4 Accuracy of Provers and Calibration Instruments

Provers and other instruments used for calibration of measurement devices must be tested for accuracy prior to first being used, immediately following (prior to being used) any repairs or alterations being conducted on them, and periodically, in accordance with the following:

- Portable provers must be calibrated biannually using measurement standards that are traceable to national standards.
- Stationary provers must be calibrated every four years using measurement standards that are traceable to national standards.
- Calibration instruments, such as manometers, thermometers, pressure gauges, deadweight testers, electronic testers, etc., must be tested for accuracy biannually against instruments having accuracy traceable to national standards.
- Master meters must be proved quarterly using a calibrated prover. The fluid used to prove the master meter must have properties similar to the fluids measured by the meters it will be used to prove. The master meter must be proved at flow rates that are comparable to the conditions it will be used for.

The procedures to be followed for these accuracy tests must be designed to provide consistent and repeatable results and must take into consideration the actual operational conditions the device will encounter. To that end, the procedures must be in accordance with the following, as available and applicable (presented in order of EUB preference from first to last):

- procedures specified by Measurement Canada (An Agency of Industry Canada),
- procedures described in the API *Manual of Petroleum Measurement Standards*,
- the device manufacturer's recommended procedures, or
- other applicable Industry-accepted procedures.

If none of the foregoing exists, the EUB will consider applications for and may grant approval of, appropriate procedures.

Records of the foregoing accuracy tests must be kept for at least one year following the expiry of the applicable test and provided to the EUB on request.

2.5 Gas Meters

2.5.1 General Calibration Requirements

The term "gas meter" is broadly used to describe all of the equipment or devices that are collectively used to arrive at an indication of a gas volume. Typically, various values (e.g., differential pressure, static pressure, temperature) must be determined and used to calculate a gas volume. Depending on the specific gas meter, each of those values may be determined by individual devices or equipment. In this section, "gas meter" means the main device through which gas flows and which typically provides an indication of flow. The term "meter element" means the devices that are associated with the gas meter but typically provide values other than the indication of flow. The term "end device" means the device or equipment that records the various values used to calculate a gas volume. In the case of electronic flow measurement, the end device may also perform the calculations necessary to arrive at the measured gas volume.

Typically, calibration of gas meter equipment requires the various meter elements to be subjected to various actual pressure, temperature, and other values that are concurrently subjected to the calibration equipment. If the end device does not indicate the same value as the calibration equipment, adjustments must be made to the meter element and/or end device.

Some meter equipment technologies may require alternative equipment and procedures for calibration, which is acceptable provided that the equipment and procedures are capable of confirming that the meter elements are functioning properly and are sensing and transmitting accurate data to the end device.

Orifice meters are commonly used to measure gas volumes in Alberta. Gas orifice meters themselves (the meter run and orifice plate-holding device) do not require calibration/proving. However, the associated meter elements and the end devices to which they are connected must be calibrated, as described in Section 2.5.3: Orifice Meters.

If devices other than orifice meters are used to measure gas, the associated meter elements and the end devices to which they are connected must be calibrated at the same frequency as orifice meters. The required procedures must be designed to provide consistent and repeatable results and must take into consideration the actual operational conditions the device will encounter. To that end, the procedures must be in accordance with the following, as available and applicable (presented in order of EUB preference from first to last):

- procedures specified by Measurement Canada,
- procedures described in the API *Manual of Petroleum Measurement Standards,*
- the device manufacturer's recommended procedures, or
- other applicable industry-accepted procedures.

If none of the foregoing exists, the EUB will consider applications for and may grant approval of appropriate procedures.

The frequency of gas meter calibration must be

- within the first calendar month of operation of a new meter,
- immediately (by the end of the calendar month) following service or repairs to the meter,
- semi-annually thereafter if the meter is used in a gas plant or for sales/delivery point, and
- annually for all other meters.

2.5.2 Gas Meter Internal Inspection

A key contributor to meter accuracy is the condition of the internal components of the gas meter. Examples of internal components are orifice plates, vortex shedder bars, and turbine rotors. The internal components must be removed from service, inspected, replaced or repaired if found to be damaged, and then placed back in service, in accordance with the following:

- The required frequency for inspection of internal gas meter components is semi-annually for gas plant accounting meters and sales/delivery point meters and annually for all other gas meters.
- Whenever possible, the inspection should be done at the same time as the calibration of the meter elements and end device, but to accommodate operational constraints the inspection may be conducted at any time, provided that the frequency requirement is met.
- Inspections must be done in accordance with procedures specified by the API, the American Gas Association (AGA), or other relevant standards organizations, other applicable industry-accepted procedures, or the device manufacturer's recommended procedures, whichever are most applicable and appropriate.
- A tag or label must be attached to the meter or end device that identifies the meter serial number, the date of the internal inspection, and any other relevant details (e.g., the size of the orifice plate installed in the meter).
- A detailed record of the inspection documenting the condition of the internal components found and any repairs or changes made to the internal components must be kept for at least one year and provided to the EUB on request.

2.5.2.1 Exceptions

1) If the "as found" calibration check of a gas meter confirms that the accuracy of all readings or outputs are within ± 0.25% of full scale (with the exception of ± 1°C for the temperature element), no adjustment of the meter is required.

2) If electronic gas meters have been found to not require adjustment for three consecutive calibrations, as indicated in #1 above, the minimum time between routine calibrations may be doubled. A tag must be attached to the meter indicating that this exception is being applied and the date of the next scheduled calibration. The records of the calibrations that qualify the meter for this exception must be kept for at least one year and made available to the EUB on request.

3) If redundant gas meters are installed for a measurement point or redundant meter elements and/or end devices are installed on a single gas meter, the minimum time between routine calibration of the meter elements and end devices may be doubled, provided that daily volumes from each end device are compared at least monthly and found to be within 0.25% of each other. If the daily volumes are not found to be within 0.25% of each other, immediate calibration of both sets of equipment is required. A tag must be attached to the meter indicating that this exception is being applied and the date of the next scheduled calibration. The records of the monthly comparisons and any calibrations that are done must be kept for at least one year and made available to the EUB on request.

4) If rotary or other types of gas meters with moving parts are used to measure gas, such as fuel gas, those meters must be proved at a frequency of once every seven years following an initial proving prior to installation. These meters must also be proved immediately following any repairs or alterations being conducted on them. The proving may be done with the meter in service, or the meter may be removed from service and proved in a shop at a pressure that is within the normal operating condition for that meter location. A tag or label must be attached to the meter that identifies the meter serial number, the date of the proving, and the meter factor determined by the proving. A detailed report indicating the details of the proving operation must be either left with the meter or readily available for inspection by the EUB. (If the detailed report is left with the meter, the foregoing requirement relating to the tag or label is considered to be met.)

5) For meters used in effluent (wet gas) measurement that require proving, such as a turbine meter, the proving must be performed by using a gas master meter or other provers in single phase proving runs. For ECF-WGR testing, see *Directive 004*.

6) If the internal components of gas meters have been found to be clean and undamaged for three consecutive inspections, the minimum time between inspections may be doubled. When the internal components are found to be dirty or damaged on any subsequent inspection, the frequency for inspections will revert back to the original requirement.

7) If the inspection of internal components of a gas meter requires the meter to be removed from service and there is no meter bypass installed, it is acceptable to defer a scheduled internal component inspection until the next time the gas meter run is shut down, provided that shutting down and depressuring the gas meter run to remove and inspect the internal components would be very disruptive to operations, require excessive flaring, or cause a safety concern, **and**

    - historical internal component inspections have proven to be satisfactory, **or**

  - the meter run is installed in a flow stream where the risk of internal component damage is low (e.g., sales gas, fuel gas), **or**
  - the measurement system at the facility provides sufficient assurance, through volumetric and/or statistical analysis, that internal component damage will be detected in a timely manner.

8) In the case of an orifice meter, if the orifice plate is mounted in a quick-change (senior) orifice meter assembly and when attempting to conduct an inspection of the orifice plate the fitting is found to be leaking between the chambers such that the meter run must be shut down and depressured to safely remove the orifice plate, it is acceptable to defer a scheduled orifice plate inspection until the next time the gas meter run is shut down, provided that
   - shutting down and depressuring the gas meter run to remove the orifice plate would be very disruptive to operations, require excessive flaring, or cause a safety concern, **and**
   - the orifice meter assembly is scheduled for repairs to be conducted the next time the gas meter run is shut down to eliminate the cause of the leak and allow future scheduled orifice plate inspections to be conducted, **and**
     - historical orifice plate inspections have proven to be satisfactory, **or**
     - the meter run is installed in a flow stream where the risk of orifice plate damage is low (e.g., sales gas, fuel gas, etc.), **or**
     - the measurement system at the facility provides sufficient assurance, through volumetric and/or statistical analysis, that orifice plate damage will be detected in a timely manner.

Note that should gas meter internal component inspections be deferred in accordance with any of the foregoing exceptions, the licensee must be able to demonstrate to the EUB, on request, that the situation meets the conditions identified. If these exceptions are being used, that must be clearly indicated on a tag or label attached to the meter (or end device). Evidence in battery or facility logs that the internal component inspection has been scheduled for the next shutdown must be available for inspection by the EUB. For the purposes of these exceptions, "shutdown" means any scheduled discontinuation of flow through the meter that is of sufficient duration to allow the operations needed to remove and inspect the internal component. If an unscheduled shutdown appears that it will allow sufficient time to conduct internal component inspection operations, the licensee should consider conducting those inspections prior to the conclusion of this unscheduled shutdown.

2.5.3 Orifice Meters

The procedure for orifice meter chart recorder (end device) calibration must be in accordance with the following:

- Pen arc, linkage, pressure stops, and spacing must be inspected and adjusted, if necessary.
- The differential pressure element must be calibrated at zero, full span, and nine ascending/descending points throughout its range. A zero check of the differential under normal operating pressure must be done before and after the calibration.
- The static pressure element must be calibrated at zero, 50% of full span, and full span.
- If a temperature element is in place, the temperature element must be calibrated at three points (operating temperature, one colder temperature, and one warmer temperature are recommended).

- If a thermometer is in place and used to determine flowing gas temperature, the thermometer must be checked at two points and replaced if found to not read accurately within ±1°C (operating temperature and one other temperature are recommended).
- If a thermometer or other temperature measuring device is not left in place (transported by an operator and used to determine flowing gas temperatures at multiple sites), the accuracy of that device must be verified at the same frequency and in the same manner as a thermometer left in place, and the record of that verification must be readily available for inspection by the EUB.
- Subsequent to the meter calibration, a tag or label must be attached to the meter (or end device) that identifies the meter serial number and the date of the calibration.
- A detailed report indicating the tests conducted on the meter during the calibration and the conditions as found and as left must be either left with the meter (or end device) or readily available for inspection by the EUB. (If the detailed report is left with the meter, the foregoing requirement relating to the tag or label is considered to be met.)

2.5.4 EFM Calibration

The procedure for calibration of an electronic flow measurement system must be in accordance with the following:

- For digital output devices, the differential pressure element must be calibrated at zero, 50% of calibrated full span, and calibrated full span.
- For analog output devices, the differential pressure element must be calibrated at zero, 50% of full span, and full span (ascending), as well as 80% and 20% of full span (descending).
- A zero check of the differential under normal operating pressure must be done before and after the calibration.
- The static pressure element must be calibrated at zero, 50% of full span, and full span.
- If a temperature element is in place, the temperature element must be verified at three points (operating temperature, one colder temperature, and one warmer temperature are recommended) and calibrated or replaced if found to not indicate accurately within ± 1°C.
- If a thermometer is in place and used to determine flowing gas temperature, the thermometer must be checked at two points and replaced if found to not read accurately within ±1°C (operating temperature and one other temperature are recommended).
- If a thermometer or other temperature measuring device is not left in place (transported by an operator and used to determine flowing gas temperatures at multiple sites), the accuracy of that device must be verified at the same frequency and in the same manner as a thermometer left in place, and the record of that verification must be readily available for inspection by the EUB.
- Subsequent to the meter calibration, a tag or label must be attached to the meter (or end device) that identifies the meter serial number and the date of the calibration.
- A detailed report indicating the tests conducted on the instruments during the calibration and the conditions as found and as left must be either left with the meter (or end device) or readily available for inspection by the EUB. (If the detailed report is left with the meter, the foregoing requirement relating to the tag or label is considered to be met.)
- If data from the instrumentation are sent to another location(s) for flow calculations via DCS, SCADA, RTU, or other means of communication, the reading of the calibration must be verified at the receipt location of such data to ensure accurate data transmission.

2.6 Oil Meters

Oil production and disposition volumes must always be reported as liquid volumes at 15°C and either equilibrium pressure (equilibrium pressure is assumed to be atmospheric pressure at the point of production or disposition) or 101.325 kilopascals (kPa) absolute pressure. However, there are two basic ways in which oil is measured that require distinctly different proving procedures. If oil production is measured prior to being reduced to atmospheric pressure, the proving procedures must allow for the volume reduction that will occur when the gas in solution with the "live" oil is allowed to evolve upon pressure reduction. No consideration for gas in solution is required when proving meters used to measure "dead" oil.

2.6.1 Live Oil Meters

Live oil meters are typically those used to measure volumes of oil or oil/water emulsion produced through test separators, but also includes meters used to measure well or group oil or oil/water emulsions that are delivered to other batteries or facilities by pipeline prior to the pressure being reduced to atmospheric.

To account for the shrinkage that will occur at the metering point due to the gas held in solution with live oil, the proving equipment and procedures may determine the amount of shrinkage either by physically degassing the prover oil volumes or by calculating the shrinkage based on an analysis of a sample of the live oil. Calculation of shrinkage volumes is most often used to mitigate safety and environmental concerns if the live oil volumes are measured at high pressures or if the live oil contains hydrogen sulphide (H_2S).

Meters used to measure live oil are subject to the following proving requirements:

- A new meter must be proved within the first calendar month of operation (note that the resultant meter factor must be applied back to the volumes measured after the commencement of operation),
- the meter must be proved immediately (by the end of the calendar month) following any repairs being conducted on the meter or any changes to the meter installation (note that the resultant meter factor must be applied back to the volumes measured after the repair or change), and
- a meter used to measure test oil or oil/water emulsion volumes must be proved annually thereafter, or
- a meter used to measure group (delivery point) oil or oil/water emulsion volumes that are delivered under pressure to another battery or facility must be proved monthly thereafter.
- The meter must be proved in line at normal operating conditions.
- The design and operation of the meter installation must ensure that the conditions of fluid flow through the meter are within the manufacturer's recommended operating range. (The meter must be installed upstream of either a throttling control valve with snap-acting on/off control or a snap-acting dump valve.)
- The size of the prover taps and operation of the prover must not restrict or alter the normal flow through the meter.
- If the proving procedure will include degassing the prover to physically reduce the pressure of the oil to atmospheric pressure:
    - The prover taps must be located downstream of the throttling/dump valve, such that the proving device will not interfere with the normal interaction of the meter and the throttling/dump valve.
    - The prover must be a tank-type volumetric or gravimetric prover.

  - Each proving run must consist of a representative volume of oil or oil/water emulsion being directed through the meter and into the prover and the liquid volume then reduced in pressure to atmospheric pressure. The resultant volume determined by the prover, after application of any required correction factors, is divided by the metered volume to determine the meter factor.
  - The amount of time required to degas the prover volume and arrive at a stable atmospheric pressure in the prover will vary, depending on the initial fluid pressure and the fluid characteristics.
- If the proving procedure will use a shrinkage factor, rather than degassing, to adjust the prover volume to atmospheric conditions:
  - The location of the prover taps depends upon the type of proving device to be used to prove the meter, such that the proving device will not interfere with the normal interaction of the meter and the throttling/dump valve (tank-type volumetric or gravimetric provers will require the taps to be downstream of the throttling/dump valve, while non-tank-type volumetric provers or master meters will require the taps to be upstream of the valve).
  - If a master meter is used for proving, it must have an uncertainty rating equal to or better than the meter it is being used to prove.
  - Each proving run must consist of a representative volume of oil or oil/water emulsion being directed through the meter and into the prover or through the master meter. The resultant volume determined by the prover or master meter, after application of any required correction factors, is divided by the metered volume to determine the meter factor.
  - A shrinkage factor representative of the fluid passing through the meter must be determined and used to adjust the meter volumes to atmospheric conditions. The shrinkage factor may either be incorporated into the meter factor or be applied to metered volumes after they are adjusted by the meter factor. The shrinkage factor must be based upon analysis of a sample of the metered fluid taken at normal operating conditions (see Section 6.3.2.3).
  - Whenever the operating conditions at the meter experience a change that could significantly affect the shrinkage factor, a new shrinkage factor must be determined based upon analysis of a sample of the metered fluid taken at the new operating conditions. Consideration should also be given to proving the meter at the new operating conditions to determine if the meter factor has been affected.
  - When this option is used, the tag attached to the meter must indicate that a shrinkage factor was used instead of degassing the prover and whether the shrinkage factor was incorporated into the meter factor or will be applied separately.
- If a meter is proved after a period of regular operation, an "as found" proving run must be performed prior to conducting any repairs on the meter or replacing the meter.
- An acceptable proving must consist of four consecutive runs (one of which may be the "as found" run), each providing a meter factor that is within ± 1.5% of the mean of the four factors. The resultant meter factor will be the average of the four applicable meter factors. (Proving procedures using more than four runs will be allowed, provided that the licensee can demonstrate that the alternative procedures provide that a meter factor that is of equal or better accuracy).
- When proving a test oil meter, a well that is representative of the battery's average well production characteristics must be directed through the test separator for each of the four runs. If there are wells in the battery with production characteristics that vary significantly from the average, the licensee should consider determining specific meter factors to be used for each of those wells.

- In the case of a test oil meter, the meter factor must include a correction factor to adjust the metered volume to 15°C (unless the meter is temperature compensated). Although the actual fluid temperature may vary with ambient temperature, it is acceptable to assume that the temperature observed at the time of proving is reasonably representative of the temperature experienced at the meter until the next proving. This requirement does not apply to meter technologies that do not require correction for temperature.
- In the case of a live oil delivery point meter, the meter factor must not include a correction factor for temperature. The meter must either be temperature compensated or a fluid temperature must be taken daily and the metered volume must be corrected to 15°C. This requirement does not apply to meter technologies that do not require correction for temperature.
- Subsequent to the meter proving, a tag or label must be attached to the meter that identifies the meter serial number, the date of the proving, the type of prover or master meter used, and the average meter factor. If the meter is connected to an electronic readout, it may be possible to program the meter factor into the software to allow the meter to indicate corrected volumes. If the meter is connected to a manual readout, it is necessary to apply the meter factor to the observed meter readings to result in corrected volumes.
- A detailed report indicating the type of prover or master meter used, the run details, and the calculations conducted during the proving must be either left with the meter or readily available for inspection by the EUB. (If the detailed report is left with the meter, the foregoing requirement relating to the tag or label is considered to be met.) If the proving involved the use of a shrinkage factor instead of degassing, a copy of the sample analysis must be attached to the proving report.

2.6.1.1 Exceptions

1) In situations where individual well production rates are so low that proving a test oil meter in accordance with the requirements listed above would require excessive time, it is acceptable to modify the proving procedures. Complete, individual proving runs requiring more than one hour are considered excessive. The following modifications, in order of EUB preference, may be used to reduce proving time:
   - Produce several wells through the test separator at one time to increase the volume available for the proving runs.
   - If the degassing procedure is being used, degas the first run only, and then use those data to calculate a shrinkage factor, which can be applied to subsequent runs conducted without degassing.
   - Use the highest rate well for all proving runs.
   - Conduct only three proving runs.

Note that the detailed proving report must clearly indicate if any of the foregoing modifications was used to prove the meter.

2) A live oil meter may be removed from service and proved in a meter shop, in accordance with the following:
   - If the meter is used to measure test volumes of conventional oil, the average rate of flow of oil of all the wells that are tested through the meter must be ≤ 2 m^3/d and no well may exceed 4 m^3/d of oil production.
   - Any meter used to measure test volumes of heavy oil (density > 920 kg/m^3) or crude bitumen may be proved in a meter shop.

- If the gas held in solution with the fluid produced through the meter is of sufficient volume to significantly affect the fluid volume indicated by the meter, consideration should be given to determining an appropriate shrinkage factor to correct for the effect of the solution gas and provide that factor to the meter calibration shop so it may be built into the meter factor.
- The meter installation must be inspected as follows, and corrective action must be taken where required:
  - The flow rate through the meter must be observed to verify that it is within the manufacturer's recommended operating ranges.
  - The dump valve must not be leaking (no flow registered between dumps).
- The shop proving may be conducted with a volumetric or gravimetric prover or with a master meter, as follows:
  - Water is typically used as the proving fluid, but varsol or some other light hydrocarbon fluid may be used for the proving.
  - Corrections for the temperature and pressure of the proving fluid must be made, where applicable.
  - If a master meter is used for proving, it must have an uncertainty rating equal to or better than the meter it is being used to prove.
  - If a meter is proved after a period of regular operation, an "as found" proving run must be performed prior to conducting any repairs on the meter or replacing the meter.
  - An acceptable proving must consist of four consecutive runs (one of which may be the "as found" run), each providing a meter factor that is within ± 0.5% of the mean of the four factors. The resultant meter factor will be the average of the four applicable meter factors.
  - Subsequent to the meter proving, a tag or label must be attached to the meter that identifies the meter serial number, the date of the proving, the fact the proving was done in a shop, and the average meter factor. If the meter is connected to an electronic readout, it may be possible to program the meter factor into the software to allow the meter to indicate corrected volumes. If the meter is connected to a manual readout, it is necessary to apply the meter factor to the observed meter readings to result in corrected volumes.
  - A detailed report indicating the type of prover or master meter used, the run details, and the calculations conducted during the proving must be either left with the meter or readily available for inspection by the EUB. (If the detailed report is left with the meter, the foregoing requirement relating to the tag or label is considered to be met.)

3) If a meter that required internal inspection is used to measure liquid hydrocarbon, the exception under item 7 in 2.5.2.1 also applies.

2.6.2 Dead Oil Meters

Dead oil meters are typically those used for delivery point (custody transfer point) measurement of clean oil that has been degassed to atmospheric pressure. These meters may be found measuring oil being pumped from a battery into a pipeline or measuring oil being pumped from a truck into a pipeline terminal, battery, or other facility.

Meters used to measure dead oil are subject to the following proving requirements:

- A new meter must be proved within the first calendar month of operation (note that the resultant meter factor must be applied back to the volumes measured after the commencement of operation),
- the meter must be proved monthly thereafter, and
- the meter must be proved immediately (by the end of the calendar month) following any repairs being conducted on the meter or any changes to the meter installation (note that the resultant meter factor must be applied back to the volumes measured after the repair or change).
- The meter must be proved in line at normal operating conditions.
- The design and operation of the meter installation must ensure that the conditions of fluid flow through the meter are within the manufacturer's recommended operating range.
- The prover taps must be located in such a manner that the connection and operation of the proving device will not interfere with the normal operation of the meter (**tank-type** volumetric or gravimetric provers must be connected downstream of the meter, but other provers, such as ball provers, pipe provers, or master meters may be connected either upstream or downstream of the meter).
- The size of the prover taps and operation of the prover must not restrict or alter the normal flow through the meter.
- Proving may be done with any suitable volumetric or gravimetric prover or a master meter.
- If a master meter is used for proving, it must have an uncertainty rating equal to or better than the meter it is being used to prove.
- Each proving run must consist of a representative volume of oil being directed through the meter and the prover or master meter. The volume measured by the prover or by the master meter, after application of any required correction factors, is divided by the metered volume to determine the meter factor.
- An acceptable initial proving (the first proving of a new or repaired meter) must consist of three consecutive runs, each providing a meter factor within ± 0.25% of the mean of the three factors. The resultant meter factor will be the average of the three applicable meter factors. (Proving procedures using more than three runs are allowed, provided that the licensee can demonstrate that the alternative procedures provide a meter factor of equal or better accuracy.)
- For provings subsequent to the initial proving, one run will be sufficient if the "as found" run provides a meter factor within ± 0.5% of the previous factor. If the factor does not meet this requirement, the procedure required for the initial proving, as described above, must be followed.
- Subsequent to the meter proving, a tag or label must be attached to the meter that identifies the meter serial number, the date of the proving, and the average meter factor. If the meter is connected to an electronic readout, it may be possible to program the meter factor into the software to allow the meter to indicate corrected volumes. If the meter is connected to a manual readout, it is necessary to apply the meter factor to the observed meter readings to result in corrected volumes.

A detailed report indicating the type of prover or master meter used, the run details, and the calculations conducted during the proving must be either left with the meter or readily available for inspection by the EUB. (If the detailed report is left with the meter, the foregoing requirement relating to the tag or label is considered to be met.)

2.6.2.1 Exceptions

1) If the volume of fluid measured by a dead oil meter does not exceed 100 m^3/d, the meter proving frequency may be extended to quarterly. The tag attached to the meter must clearly indicate that the meter measures ≤ 100 m^3/d and that the meter is on a quarterly proving frequency. The required proving frequency will revert back to monthly if the meter begins measuring volumes >100 m^3/d.

2) If the meter factor has been found to be within 0.5% of the previous factor for three consecutive months, the meter proving frequency may be extended to quarterly. The tag attached to the meter must clearly indicate that the meter has been found to have consistent meter factors and is on a quarterly proving frequency. The required proving frequency will revert back to monthly whenever the meter factor determined during a proving is found to not be within 0.5% of the previous factor.

2.7 Condensate Meters

Condensate is subject to two differing sets of measurement/accounting/reporting rules. If condensate volumes are measured and delivered at atmospheric pressure or equilibrium pressure, the volume must be determined and reported as a liquid volume at 15°C and equilibrium pressure (equilibrium pressure is assumed to be either atmospheric pressure at the point of production or disposition or the actual equilibrium pressure). If condensate volumes are measured and delivered at flow-line conditions, the volume must be determined at flow-line pressure and corrected to 15°C, but the volume is reported as a gas equivalent volume at standard conditions (101.325 kPa absolute and 15°C).

2.7.1 Condensate at Equilibrium Conditions

Meters that measure condensate that is stored and delivered as a liquid at atmospheric pressure or equilibrium pressure are typically "delivery point" meters and are therefore subject to the same proving requirements and exceptions applicable to meters used for dead oil measurement (see Section 2.6.2).

2.7.2 Condensate at Flow-line Conditions

When a meter that requires proving is used to measure condensate at flow-line conditions, it must be subjected to the following proving requirements:

- The meter must be proved immediately (by the end of the calendar month) following any repairs being conducted on the meter or any changes to the meter installation (note that the resultant meter factor must be applied back to the volumes measured after the repair or change).
- The meter must be proved in line at flow-line conditions.
- The design and operation of the meter installation must ensure that the flow through the meter is within the manufacturer's recommended operating range. (The meter must be installed upstream of either a throttling control valve with snap-acting on/off control or a snap-acting dump valve.)
- The size of the prover taps and operation of the prover must not restrict or alter the normal flow through the meter.
- The location of the prover taps must be such that the connection of the proving device will not interfere with the normal interaction of the meter and the dump valve:
    - If a tank-type volumetric or gravimetric prover is used, the prover taps must be located downstream of the dump valve, and the pressure in the prover must be

regulated such that reduction of the condensate volume due to flashing is minimized. The dump valve must be allowed to control the flow of condensate into the prover through its normal operation. Flow into the prover is not to be controlled by manual manipulation of the prover inlet valve.

  - If a ball or piston-type volumetric prover or a master meter is used, the prover taps must be located upstream of the dump valve, so that the prover or master meter will be subjected to the same flow and pressure conditions as the condensate meter being proved.

- If a master meter is used for proving, it must have an uncertainty rating equal to or better than the meter it is being used to prove.
- Each proving run must consist of a representative volume of condensate being directed through the meter and the prover or master meter. The volume measured by the prover or by the master meter, after application of any required correction factors, is divided by the metered volume to determine the meter factor.
- If a meter is proved after a period of regular operation, an "as found" proving run must be performed prior to conducting any repairs on the meter or replacing the meter.
- An acceptable proving must consist of four consecutive runs (one of which may be the "as found" run), each providing a meter factor that is within ± 2% of the mean of the four factors. The resultant meter factor will be the average of the four applicable meter factors. (Proving procedures using more than four runs will be allowed, provided that the licensee can demonstrate that the alternative procedures provide that a meter factor of equal or better accuracy.)
- Subsequent to the meter proving, a tag or label must be attached to the meter that identifies the meter serial number, the date of the proving, the type of prover or master meter used to prove the meter, and the average meter factor. If the meter is connected to an electronic readout, it may be possible to program the meter factor into the software to allow the meter to indicate corrected volumes. If the meter is connected to a manual readout, it is necessary to apply the meter factor to the observed meter readings to result in corrected volumes.
- A detailed report indicating the type of prover or master meter used, the run details, and the calculations conducted during the proving must be either left with the meter or readily available for inspection by the EUB. (If the detailed report is left with the meter, the foregoing requirement relating to the tag or label is considered to be met.)

2.7.2.1 Exceptions

1) A meter used to measure condensate at flow-line conditions may be removed from service and proved in a meter shop, in accordance with the following:
   - If the meter is used to measure condensate production on a continuous basis, the rate of flow through the meter must be ≤2 m^3/d, or the rate of flow through the meter must be ≤3 m^3/d with the gas equivalent volume of the daily condensate volume being ≤3% of the daily gas volume related to the condensate production. If the meter is used on a portable test unit, there is no volume limitation, but consideration should be given to proving the meter in line if significant condensate production is observed during the test.
   - The meter installation must be inspected as follows, and corrective action must be taken where required:
     - The flow rate through the meter must be observed to verify that it is within the manufacturer's recommended operating ranges.
     - The dump valve must not be leaking (no flow registered between dumps).

- The shop proving may be conducted with a volumetric or gravimetric prover, or with a master meter, as follows:
  - Water is typically used as the proving fluid, but varsol or some other light hydrocarbon fluid may be used for the proving.
  - If a master meter is used for proving, it must have an uncertainty rating equal to or better than the meter it is being used to prove.
  - Corrections for the temperature and pressure of the proving fluid must be made, where applicable.
  - If a meter is proved after a period of regular operation, an "as found" proving run must be performed prior to conducting any repairs on the meter or replacing the meter.
  - An acceptable proving must consist of four consecutive runs (one of which may be the "as found" run), each providing a meter factor within ± 0.5% of the mean of the four factors. The resultant meter factor is the average of the four applicable meter factors.
  - Subsequent to the meter proving, a tag or label must be attached to the meter that identifies the meter serial number, the date of the proving, the fact the proving was done in a shop, and the average meter factor. If the meter is connected to an electronic readout, it may be possible to program the meter factor into the software to allow the meter to indicate corrected volumes. If the meter is connected to a manual readout, it is necessary to apply the meter factor to the observed meter readings to result in corrected volumes.
  - A detailed report indicating the type of prover or master meter used, the run details, and the calculations conducted during the proving must be either left with the meter or readily available for inspection by the EUB. (If the detailed report is left with the meter, the foregoing requirement relating to the tag or label is considered to be met.)

2) If a meter used to measure condensate at flow-line conditions is a type that uses no internal moving parts (e.g., orifice meter, vortex meter, V-cone meter), it does not require proving, provided that the following conditions are met:
   - Flow through the meter must be continuous and maintained within the rates specified by the meter manufacturer as providing accurate measurement.
   - The design and operation of the entire meter system must be in accordance with the meter manufacturer's specifications.
   - The meter end device(s) must be calibrated at the frequencies specified for flow-line condensate meters above, using procedures specified by the API in the Manual of Petroleum Measurement Standards, the AGA, the device manufacturer, or other applicable industry-accepted procedures, whichever are most appropriate and applicable.
   - The internal components of the primary meter device must be removed from service annually, inspected, replaced or repaired if found to be damaged, and then placed back in service, in accordance with procedures specified by the API, the AGA, other relevant standards organizations, other applicable industry-accepted procedures, or the device manufacturer's recommended procedures, whichever are most applicable and appropriate.
   - Whenever possible, the inspection of internal components should be done at the same time as the meter end device calibration, but to accommodate operational constraints the inspection may be conducted at any time, provided the frequency requirement is met.

- A tag or label must be attached to the meter (or end device) that identifies the primary device serial number and the date of the calibration.
- A tag or label must be attached to the meter (or end device) that identifies the primary device serial number, the date of the internal components inspection, and any other relevant details (e.g., the size of the orifice plate installed in the meter).
- A detailed report indicating the tests conducted on the meter during the calibration and the conditions as found and as left must be either left with the meter (or end device) or readily available for inspection by the EUB. (If the detailed report is left with the meter, the foregoing requirement relating to the tag or label is considered to be met.)
- A detailed record of the internal components inspection documenting the condition of the internal components as found and any repairs or changes made to the internal components must be either left with the meter (or end device) or readily available for inspection by the EUB. (If the detailed report is left with the meter, the foregoing requirement relating to the tag or label will be considered to be met.)

2.8 Other Liquid Hydrocarbon Meters

Meters used to measure other high vapour pressure liquid hydrocarbons, such as propane, butane, pentanes plus, natural gas liquid/liquid petroleum gas (NGL/LPG), etc., are subject to the same proving requirements and exceptions as are meters used for measurement of condensate at equilibrium conditions or measurement of dead oil (see above).

2.9 Water Meters

If a meter is used to measure water production, injection, or disposal or injection of other water-based fluids, the meter must be installed upstream of either a throttling control valve with snap-acting on/off control or a snap-acting dump valve, if used and proved

- within the first three months of operation (note that the meter factor may be assumed to be 1.0000 until the first proving is conducted),
- annually thereafter, and
- immediately (by the end of the calendar month) following any repairs being conducted on or replacement of the meter. (Note that the resultant meter factor must be applied back to the volumes measured since the date of repair/change.)

The proving may be conducted in line at field operating conditions, or the meter may be removed from service and proved in a meter shop, using water as the test fluid.

The proving may be conducted using a volumetric prover, a gravimetric prover, or a master meter. Where a master meter is used for proving, it must have an uncertainty rating equal to or better than the meter it is being used to prove. Correction factors, as appropriate, must be used to adjust volumes to 15°C.

If a meter is proved after a period of regular operation, an "as found" proving run must be performed prior to conducting any repairs on the meter or replacing the meter. An acceptable proving must consist of four consecutive runs (one of which may be the "as found" run), each providing a meter factor within ± 1.5% of the mean of the four factors. The resultant meter factor is the average of the four applicable meter factors. (Proving procedures using more than four runs will be allowed, provided that the licensee can demonstrate that the alternative procedures provide a meter factor of equal or better accuracy.)

Following the meter proving, a tag or label must be attached to the meter that identifies the meter serial number, the date of the proving, and the average meter factor. If the meter is connected to an electronic readout, it may be possible to program the meter factor into the software to allow the meter to indicate corrected volumes. If the meter is connected to a manual readout, it is necessary to apply the meter factor to the observed meter readings to result in corrected volumes.

A detailed report indicating the type of prover or master meter used, the run details, and the calculations conducted during the proving must be either left with the meter or readily available for inspection by the EUB. (If the detailed report is left with the meter, the foregoing requirement relating to the tag or label is considered to be met.)

Exception

If a meter used to measure water or other water-based fluids is a type that uses no internal moving parts (e.g., orifice meter, vortex meter, V-cone meter), it does not require proving, provided that the following conditions are met:

- Flow through the meter must be continuous and maintained within the rates specified by the meter manufacturer as providing accurate measurement.
- The design and operation of the entire meter system must be in accordance with the meter manufacturer's specifications.
- The meter end device(s) must be calibrated at the frequencies specified above for water meters, using procedures specified by the API in the Manual of Petroleum Measurement Standards, the AGA, the device manufacturer, or other applicable industry-accepted procedures, whichever are most appropriate and applicable.
- The internal components of the primary meter device must be removed from service annually, inspected, replaced or repaired if found to be damaged, and then placed back in service, in accordance with procedures specified by the API, the AGA, other relevant standards organizations, other applicable industry-accepted procedures, or the device manufacturer's recommended procedures, whichever are most applicable and appropriate.
    - Whenever possible, the inspection of internal components should be done at the same time as the meter end device calibration, but to accommodate operational constraints the inspection may be conducted at any time, provided the frequency requirement is met.
    - A tag or label must be attached to the meter (or end device) that identifies the primary device serial number and the date of the calibration.
    - A tag or label must be attached to the meter (or end device) that identifies the primary device serial number, the date of the internal inspection, and any other relevant details (e.g., the size of the orifice plate installed in the meter).
    - A detailed report indicating the tests conducted on the meter during the calibration and the conditions as found and as left must be either left with the meter (or end device) or readily available for inspection by the EUB. (If the detailed report is left with the meter, the foregoing requirement relating to the tag or label is considered to be met.)
    - A detailed record of the internal components inspection documenting the condition of the internal components as found and any repairs or changes made to the internal components must be either left with the meter (or end device) or readily available for inspection by the EUB. (If the detailed report is left with the meter, the foregoing requirement relating to the tag or label is considered to be met.)

2.10 Product Analyzers

If a product analyzer (water cut analyzer) is used to determine water production, it must be calibrated annually using procedures recommended by the manufacturer.

Following the calibration, a tag or label must be attached to the product analyzer that identifies the analyzer serial number and the date of the calibration. A detailed report indicating the calibration procedure used and the calibration details must be either left with the analyzer or readily available for inspection by the EUB. (If the detailed report is left with the analyzer, the foregoing requirement relating to the tag or label is considered to be met.)

2.11 Automatic Tank Gauges

2.11.1 Inventory Measurement

If automatic tank gauge devices are used to indicate fluid levels in tanks for monthly inventory measurement, they must be calibrated on site within the first month of operation. The calibration procedures must be in accordance with the following, as available and applicable (presented in order of EUB preference from first to last):

- the device manufacturer's recommended procedures,
- procedures described in the API *Manual of Petroleum Measurement Standards*, or
- other applicable industry-accepted procedures.

If none of the foregoing exists, the EUB will consider applications for and may grant approval of appropriate procedures.

A record of the calibration must be made available to the EUB on request.

2.11.2 Delivery Point Measurement

If automatic tank gauge devices are used to indicate fluid levels in tanks for delivery point measurement of oil or oil/water emulsion, such as truck volume receipts at batteries/facilities or batch deliveries into a pipeline, they must be calibrated on site within the first month of operation and monthly thereafter. The calibration procedures must be in accordance with the following, as available and applicable (presented in order of EUB preference from first to last):

- the device manufacturer's recommended procedures,
- procedures described in the API Manual of Petroleum Measurement Standards, or
- other applicable industry-accepted procedures.

If none of the foregoing exists, the EUB will consider applications for and may grant approval of appropriate procedures.

A record of the calibration must be made available to the EUB on request.

Exception

Where the accuracy of an automatic tank gauge is found to be within 0.5% of full scale for three consecutive months, the calibration frequency may be extended to quarterly. The record of calibration must clearly indicate that the device has been found to demonstrate consistent accuracy and is on a quarterly calibration frequency. The records of the calibrations that qualify the device for this exception must be kept and made available to the EUB on request.

The calibration frequency will revert back to monthly whenever the accuracy is found to not be within 0.5% of full scale.

2.12 Using Tank Gauging for Oil Measurement

Tank gauging refers to determining levels in a tank and using those levels to calculate a volume increase or decrease in the tank. The level may be determined by using an automatic tank gauge device or by manually determining the level with a gauge tape. In either case, the volume of the tank relative to its height at any given point must be determined. This is referred to as the tank calibration, or tank strapping, and results in the creation of a tank gauge table.

2.12.1 Inventory Measurement

If tank gauging is used only for monthly inventory measurement, specific tank calibration procedures are not required. It is acceptable to use gauge tables provided by the tank manufacturer or, if those are unavailable, generic gauge tables applicable to the tank size/type being used.

2.12.2 Delivery Point Measurement

If tank gauging is used for delivery point measurement of oil or oil/water emulsion, such as truck volume receipts at batteries/facilities or batch deliveries into a pipeline, the specific tanks being used must be calibrated on site within the first month of operation and any time the tank is damaged or altered. The calibration must result in the creation of a gauge table for each tank, which must then be used in conjunction with tank gauge readings to determine volumes. Calibration procedures must be in accordance with applicable methods stipulated in the API *Manual of Petroleum Measurement Standards*.

A record of the calibration must be made available to the EUB on request.

2.13 Weigh Scales

Weigh scales used to measure oil/water emulsion and clean oil receipts at batteries, custom treating plants, pipeline terminals, and other facilities must be approved and inspected prior to use, in accordance with Measurement Canada requirements.

Weigh scales must be tested for accuracy in accordance with the following schedule:

- monthly,
- immediately (by the end of the calendar month) following any incident in which the scale may have been damaged, and
- immediately (by the end of the calendar month) following any changes or modifications being made to the scale.
- The complete set of procedures set out by Measurement Canada for determining weigh scale accuracy must be used following any damage or modifications and at least annually.

The monthly accuracy tests may be done using the complete set of procedures set out by Measurement Canada or, as a minimum, using the following abbreviated procedure:

1) Zero check: Determine if the scale reads zero with no weight on the scale.
2) Add a 10 kg standard weight: Determine if the scale reads 10 kg.
3) Remove the 10 kg standard weight: Determine if the scale returns to zero.

4) Add a test load consisting of 10 000 kg of standard weights or, alternatively, durable object(s) of known weight (minimum 5000 kg): Determine if the scale reads the correct weight of the test load (acceptable error is ±0.2% of the test load).

5) Add a loaded truck, typical of the loads routinely handled by the scale: Note the total weight of the test load and truck.

6) Remove the test load and note the weight of the truck alone: Determine if the scale reading correctly indicates the removal of the test load (acceptable error is ±0.2% of the test load).

7) Remove the truck: Determine if the scale returns to zero with no weight on the scale.

If as a result of the foregoing tests the weigh scale is found to not be accurate, it must be calibrated and retested until found to be accurate and then sealed by a heavy-duty scale service company. The service company must then send a written report to Measurement Canada documenting the adjustment and/or repairs.

A detailed record of the accuracy tests and any calibration activities must be kept in close proximity to the weigh scale, retained for at least one year, and made available to the EUB on request. This record must include the following information:

- make, model, serial number, and capacity of the weigh scale and any associated equipment,
- date of the accuracy test,
- details of the tests performed and the results noted, and
- details regarding any alterations or calibration performed on the weigh scale.

Exceptions

1) If the volume of fluid measured by a weigh scale does not exceed 100 m^3/d, the monthly accuracy test frequency may be extended to quarterly. The detailed record of the accuracy tests must clearly indicate that the weigh scale measures ≤ 100 m^3/d and that the weigh scale is on a quarterly testing frequency. The required testing frequency will revert back to monthly if the weigh scale begins measuring volumes in excess of 100 m^3/d.

2) If the weigh scale has been found to not require calibration adjustments for three consecutive months, the monthly accuracy test frequency may be extended to quarterly. The required accuracy test frequency will revert back to monthly whenever a quarterly accuracy test determines that the weigh scale requires calibration adjustments.

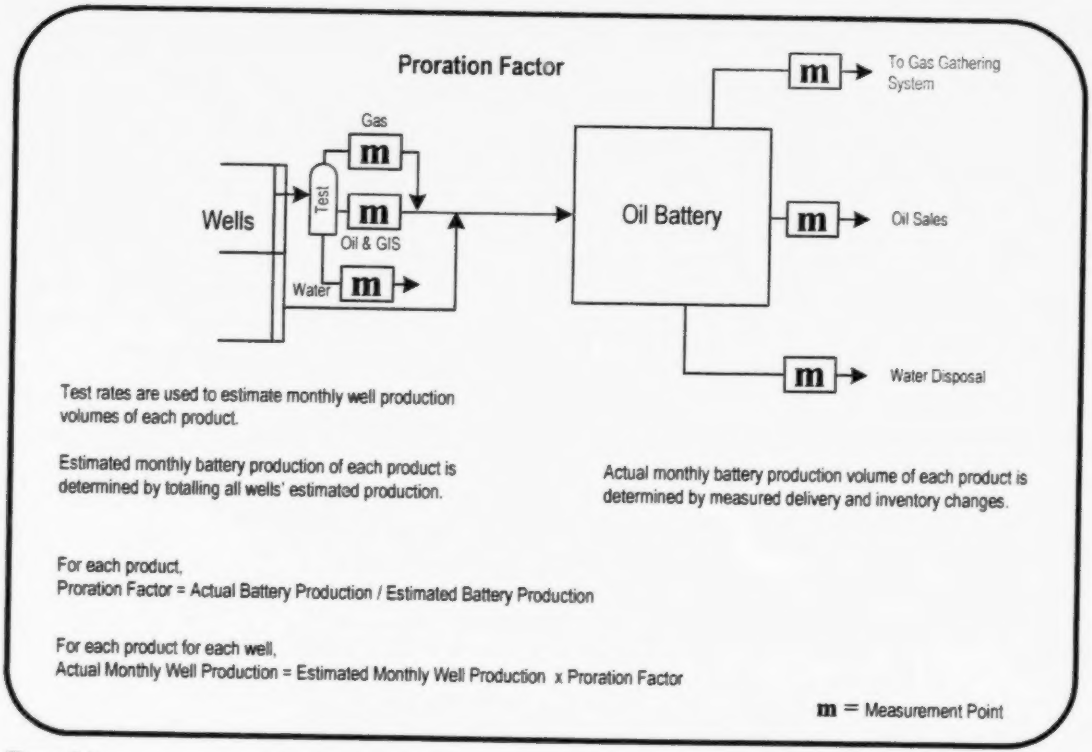
3 Proration Factors, Allocation Factors, and Metering Difference

3.1 Proration Factors and Allocation Factors

Description

Proration is an accounting system or procedure where the total actual monthly battery production is equitably distributed among wells in the battery. This system is applicable when the production of wells producing to a battery is commingled before separation and measurement, and each well's monthly production is initially estimated, based on well test data. In this type of system, proration factors are used to correct estimated volumes to actual volumes.

In the case of an oil proration battery (Figure 3.1), the oil, gas, and water produced by individual wells are not continuously measured. Instead, the wells are periodically tested to determine the production rates of oil, gas, and water. The rates determined during the well test are used to estimate the well's production for the time period beginning with the well test and continuing until another test is conducted. The estimated monthly production so determined for each well in the battery is totalled to arrive at the battery's total monthly estimated production. The total actual oil, gas, and water production volumes for the battery are determined, and for each fluid, the total actual volume is divided by the total estimated production to yield a "proration factor." The proration factor is multiplied by each well's estimated production to yield the well's actual production. Similar accounting procedures are used for gas batteries subject to proration.



Test rates are used to estimate monthly well production volumes of each product.

Estimated monthly battery production of each product is determined by totalling all wells' estimated production.

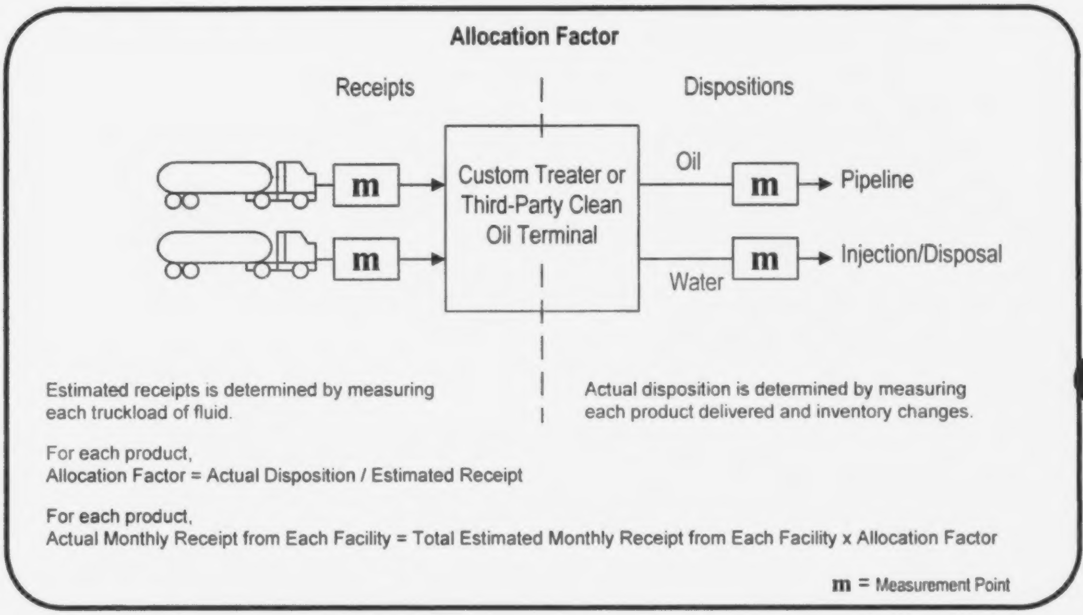
Actual monthly battery production volume of each product is determined by measured delivery and inventory changes.

For each product,
Proration Factor = Actual Battery Production / Estimated Battery Production

For each product for each well,
Actual Monthly Well Production = Estimated Monthly Well Production x Proration Factor

Figure 3.1

An “allocation factor” is a type of proration factor. It is used at facilities where only fluids received by truck are handled, such as custom treating plants and third-party-operated clean oil terminals (Figure 3.2). The name of the factor has been chosen to reflect the differences between batteries that receive fluids from wells through flow lines (where proration factors are used) and facilities that receive fluids from batteries only by truck (where allocation factors are used). The purpose of an allocation factor is similar to a proration factor, in that it is used to correct fluid receipt volumes (considered estimates) to actual volumes based on disposition measurements taken at the outlet of the facility (and also considering inventory change). The allocation factor is determined by dividing the monthly total actual volume for each fluid by the monthly total estimated volume for each fluid. The total estimated volume of each fluid received from each source is multiplied by the allocation factor for that fluid to yield the actual volume received from that source.



Estimated receipts is determined by measuring each truckload of fluid.

Actual disposition is determined by measuring each product delivered and inventory changes.

For each product,
Allocation Factor = Actual Disposition / Estimated Receipt

For each product,
Actual Monthly Receipt from Each Facility = Total Estimated Monthly Receipt from Each Facility x Allocation Factor

Figure 3.2

The allocation factors discussed in this section are not to be confused with the process whereby products delivered out of a gas plant are “allocated” back to each well in the system, based on individual well production volumes and gas analyses.

Measurement accuracy and uncertainty generally relate to random errors and, as such, are not directly comparable to proration and allocation factors, which generally relate to bias errors. The EUB Standards of Accuracy (Section 1) focus on specific measurement points (i.e., inlet or outlet), whereas proration and allocation factors relate to a comparison of inlet (or estimated production) to outlet measurement. It is important to note that target factors for different products may be different due to the products being subjected to different levels of uncertainty. For example, the target factors for oil and water in a conventional oil proration battery are different, because while the estimated production volumes of oil and water are determined by the same type of measurement, the outlet volumes of the clean oil and water are not determined by the same type of measurement.

When measurement equipment and procedures conform to all applicable standards, it is assumed that the errors that occur in a series of measurements will be either plus or minus and will cancel each other out to some degree. Where a bias error occurs in a series of measurements, there will be no plus/minus and all of the measurements are assumed to be in error by the same amount and in the same direction. Proration factors and allocation factors are therefore used to equitably correct all measurements for biased errors.

3.1.2 Target Factors

If measurement and accounting procedures meet applicable requirements, any proration factor or allocation factor should be acceptable, since it is assumed that the factor will correct for a bias error that has occurred. However, the EUB expects proration factors and allocation factors to be monitored by operators and used as a "warning flag" to identify when the measurement system at a battery or facility is experiencing problems that need investigation.

The EUB deems the ranges of proration factors and allocation factors indicated below to be acceptable targets. When a factor is found to exceed these limits, the licensee is expected to investigate the cause of the factor being outside the target range and document the results of the investigation and the actions taken to correct the situation. The EUB acknowledges that in some batteries or facilities, physical limitations and/or the economics applicable to a particular situation may prohibit the resolution of situations where factors are consistently in excess of the targets indicated below. In that case, the licensee must also document the reason(s) that prohibit further action from being taken. This information does not have to be routinely submitted to the EUB, but must be available to the EUB on request for audit.

If the cause of a factor being outside these ranges is determined and the error can be quantified, the EUB expects the reported production data to be amended, thereby bringing the factor back into line. If the cause is determined and action is taken to correct the situation for future months, but the findings are not quantifiable for past months, no amendments need to be submitted.

3.1.3 Exception

An exception to the foregoing procedure is allowed for conventional oil proration batteries if based on average rates determined semi-annually,

- all wells in the battery produce ≤ 2 m^3/d of oil, or
- the majority of the wells in the battery produce ≤ 2 m^3/d of oil and no well produces >6 m^3/d of oil.

In this case the licensee should still be aware of the proration factors and take corrective action where necessary, but need not expend a great deal of effort to conduct an investigation and document the results.

3.1.4 Acceptable Proration Factors and Allocation Factor Ranges

Proration Factors
Conventional oil battery
- oil = 0.95000 – 1.05000
- gas = 0.90000 – 1.10000
- water = 0.90000 – 1.10000

Heavy oil battery – primary production and waterflood operations
- oil = 0.85000 – 1.15000
- water = 0.85000 – 1.15000
- gas = no stated expectation due to generally low production volumes

Heavy oil battery – thermal recovery operations
- oil = 0.75000 – 1.25000
- water = 0.75000 – 1.25000
- gas = no stated expectation due to the nature of thermal production

Gas battery – dry gas production
- gas = 0.90000 – 1.10000

Gas battery – effluent measurement
- gas = 0.90000 – 1.10000
- water = 0.90000 – 1.10000

Allocation Factors
Custom treating plant
- oil = 0.95000 – 1.05000
- water = 0.90000 – 1.10000

Clean oil terminal (third-party operated, where applicable)
- oil = 0.95000 – 1.05000

3.2 Metering Difference

3.2.1 Description

For EUB production reporting purposes, a "metering difference" is used to balance, on a monthly basis, any difference that occurs between the measured inlet/receipt volumes and the measured outlet/disposition volumes at a facility. Metering difference is generally acceptable as an accounting/reporting entity if a difference results from two or more measurements of the same product. Metering differences occur because no two measurement devices provide the exact same volume, due to the uncertainties associated with the devices. However, a more significant cause of metering differences is that the product measured at the inlet to a facility is usually altered by the process within the facility, resulting in a different product or products being measured at the outlet of the facility. It should be noted that metering difference differs from proration and allocation factors in that for batteries or facilities where those factors are used, the difference occurs between "estimated" and "actual" volumes.

Metering difference may be used as follows:

Injection/disposal systems (Figure 3.3)—Receipts into these facilities are typically measured prior to being split up and delivered to individual wells, where each well's volume is measured prior to injection/disposal.

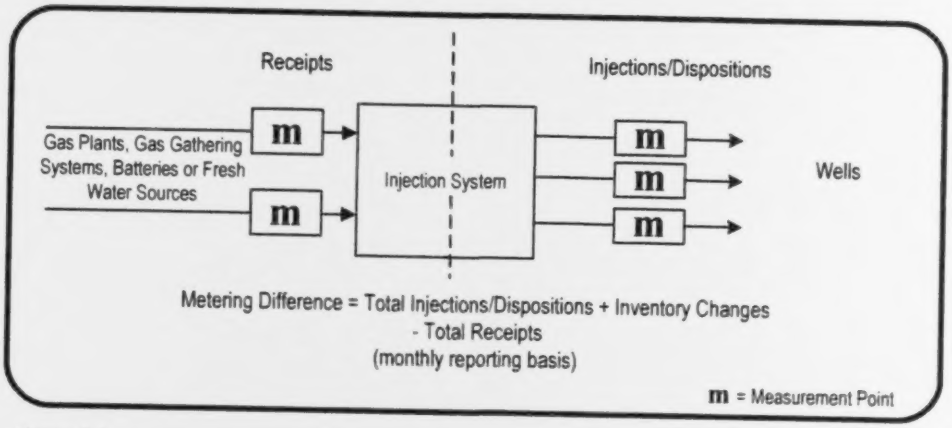

Receipts
Injections/Dispositions
Gas Plants, Gas Gathering Systems, Batteries or Fresh Water Sources
m
m
Injection System
m
m
m
Wells
Metering Difference = Total Injections/Dispositions + Inventory Changes - Total Receipts
(monthly reporting basis)
m = Measurement Point

Figure 3.3

Batteries (Figure 3.4)—Metering difference may be used for gas and water production only, and only in limited, specific situations where there is both inlet and outlet measurement for reporting purposes. Such an example is a crude oil group battery where each well's gas production is measured and the combined gas stream is measured again before being sent to a gas gathering system or gas plant. However, metering difference would rarely be appropriate for use in a proration battery.

Gas gathering systems (Figure 3.4)—Receipts into these facilities are typically measured prior to being subjected to some sort of limited processing, which may include liquids removal and compression, and the resultant product(s) is measured prior to delivery to a sales point or to a gas plant for further processing.

Gas plants (Figure 3.4)—Receipts into these facilities are typically measured prior to being processed into salable products, and those products are measured prior to delivery to a sales point.

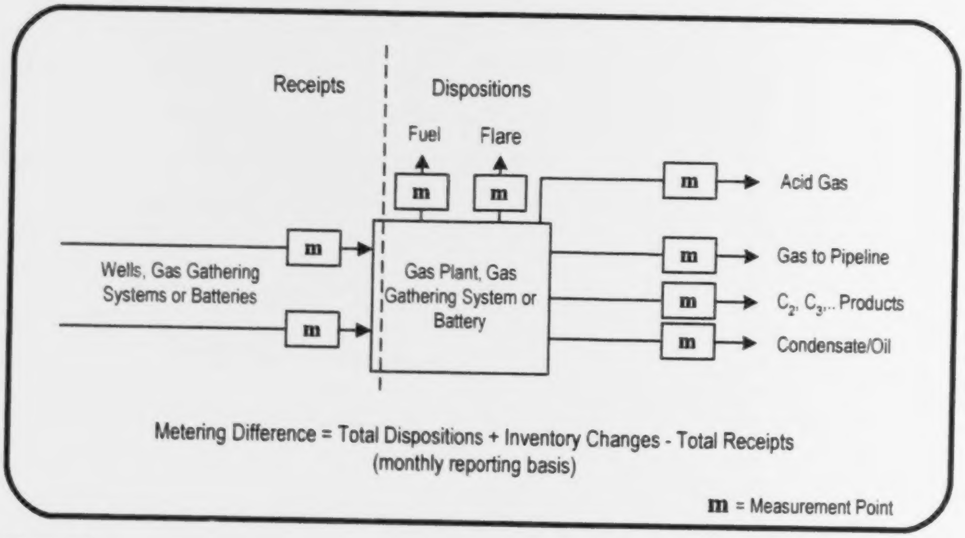

Receipts
Dispositions
Fuel
Flare
m
m
m
Acid Gas
Wells, Gas Gathering Systems or Batteries
m
m
Gas Plant, Gas Gathering System or Battery
m
Gas to Pipeline
m
C2, C3,.. Products
m
Condensate/Oil
Metering Difference = Total Dispositions + Inventory Changes - Total Receipts
(monthly reporting basis)
m = Measurement Point

Figure 3.4

3.2.2 Target Metering Difference

If measurement and accounting procedures meet applicable requirements, metering differences up to ±5% of the total inlet/receipt volume are deemed to be acceptable. The EUB expects the metering difference to be monitored by licensees and used as a warning flag to identify when the measurement system at a battery or facility is experiencing problems that need investigation.

When a metering difference is found to exceed 5%, the licensee is expected to investigate the cause of the poor metering difference and document the results of the investigation and the actions taken to correct the situation. The EUB acknowledges that in some batteries or facilities, physical limitations and/or the economics applicable to a particular situation may prohibit the resolution of situations where the metering difference is consistently in excess of the target indicated. In such cases, the licensee must also document the reason(s) that prohibit further action from being taken. This information does not have to be routinely submitted to the EUB, but must be available to the EUB on request for audit.

If the cause of a poor metering difference is determined and the error can be quantified, the EUB expects the incorrectly reported production data to be amended, thereby bringing the metering difference back into line. If the cause is determined and action is taken to correct the situation for future months, but the findings are not quantifiable for past months, no amendments need to be submitted.

4 Gas Measurement

This section presents the base requirements and exceptions for gas measurement from any source in the upstream and midstream oil and gas industry that are used for determining volumes for reporting to the EUB.

4.1 General Requirements

All gas production and injection must be continuously and accurately measured with a measurement device or determined by engineering estimation if exception conditions described below are met or site-specific EUB approval has been obtained.

A gas measurement system is in compliance if the following base requirements are met. A licensee may deviate from these base requirements if the conditions in Section 4.3.5: Exceptions are met. Section 1: Standards of Accuracy provides further information relating to situations when other deviations may be acceptable.

Monthly gas volumes must be reported in units of 10^3 m^3 and rounded to 1 decimal place.

Standard or base conditions for use in calculating and reporting gas volumes are 101.325 kPa (absolute) and 15°C.

4.2 Gas Measurement and Accounting Requirements for Various Battery/Facility Types

4.2.1 Oil/Bitumen Batteries

4.2.1.1 General

- All wells in the battery must be classified as oil or bitumen wells.
- All wells in a multiwell battery must be subject to the same type of measurement. If there is a mixture of measured and prorated wells within the same battery, EUB exception criteria in Section 5: Site-specific Deviation from Base Requirements under "Measurement by Difference" must be met or EUB site-specific approval must be obtained.
- Production from gas batteries or other oil/bitumen batteries may not be connected to an oil/bitumen proration battery upstream of the oil/bitumen battery group gas measurement point unless specific criteria are met and/or EUB approval of an application is obtained. See Section 5: Site-specific Deviation from Base Requirements under "Measurement by Difference" for examples.

Single-well Battery

- Gas must be separated from oil/bitumen or emulsion and measured (or estimated where appropriate) as a single phase.

Multiwell Group Battery

- Each well must have its own separation and measurement equipment, similar to a single-well battery.
- All equipment for the wells in the battery must share a common surface location.

Proration Battery

- All well production is commingled prior to the total battery gas being separated from oil/bitumen or emulsion and measured (or estimated where appropriate) as a single phase.

- Individual monthly well gas production is estimated based on periodic well tests and corrected to the actual monthly volume through the use of a proration factor.

4.2.2 Gas Batteries / Facilities

General

- All wells in the battery must be classified as gas wells.
- Gas wells may produce condensate or oil.
- All wells in a multiwell battery must be subject to the same type of measurement. If there are mixtures of measured and prorated wells (mixed measurement) within the same battery, EUB exception criteria in Section 5: Site-specific Deviation from Base Requirements under "Measurement by Difference" must be met, or EUB site-specific approval must be obtained, and the measured well(s) must have their own separate battery code(s) to deliver gas into the proration battery.
- All wells in a multiwell battery must be connected by pipeline to a common point.
- Gas production from oil/bitumen wells or batteries or from other gas wells or batteries may not be connected to a gas proration battery upstream of the gas proration battery group measurement point unless EUB exception criteria in Section 5: Site-specific Deviation from Base Requirements under "Measurement by Difference" are met or EUB site-specific approval is obtained.
- Gas wells that are designed to operate on an on/off cycle basis using plunger lifts, on/off controllers, manual on/off, etc., or pumpjacks must report well status on the Registry as GAS PUMP instead of GAS FLOW.
- Any facility, such as a well site, gas plant, battery, or individual compressor site, that is designed to consume fuel gas exceeding 0.5 10^3 m^3/d must have fuel gas measurement from DATE of implementation onwards. If it is a part of another facility on the same site, the overall site fuel gas used must be measured. The 0.5 10^3 m^3/d measurement limit also applies to flare and vent gas streams, excluding heavy oil and crude bitumen batteries.

Single-well Battery

- Gas must be separated from water and condensate or oil (if applicable) and measured as a single phase.
- Condensate produced must be reported as a liquid if it is disposed of from the well site without further processing.
- Condensate that is recombined with the gas production after separation and measurement or trucked from the well site to a gas plant for further processing must be converted to a gas equivalent volume and added to the measured single-phase gas volume for reporting purposes.
- Oil produced in conjunction with the gas must be reported as oil at stock tank conditions. The gas-in-solution (GIS) with the oil at the point of measurement must be estimated and added to the gas production volume. See Section 4.3.5.4.

Multiwell Group Battery

- Each well must have its own separation and measurement equipment, similar to a single-well battery.
- The wells in the group battery may all be identical with regard to handling of condensate, or there may be a mixture of methods for handling condensate. The rules for reporting condensate as a gas equivalent or as a liquid are the same as those for single-well gas batteries (above).

Multiwell Effluent Proration Battery

- The production from each well is subject to total effluent (wet gas) measurement, without separation of phases prior to measurement.
- Estimated well gas production is the effluent metered volume multiplied by an effluent correction factor (ECF) that is determined from periodic tests conducted at each well whereby a test separator is connected downstream of the effluent meter and the volumes measured by the test separator are compared to the volume measured by the effluent meter.
- Estimated well water production is determined by multiplying the water gas ratio (WGR), which is determined from the periodic tests, by the estimated well gas production.
- The combined (group) production of all wells in the effluent proration battery must have three-phase separation or equivalent and be measured as single-phase components, and the resulting total actual battery gas volume (including gas equivalent volume [GEV] of condensate) and total actual battery water volume must be prorated back to the wells to determine each well's actual gas and water production. If condensate is trucked out of the group separation and measurement point without further processing to a sales point, total battery gas must include the GEV of condensate and be reported as delivered to a gas gathering system, and the gas gathering system then reports the liquid condensate delivery. If liquid condensate is trucked to a gas plant for further processing, the condensate must be reported as a gas equivalent.

Multiwell Proration Battery

- Production from the wells in the battery is commingled prior to separation and measurement at a central location.
- Production from each well is not continuously measured, but is estimated based on periodic tests conducted at each well.
- The combined production of all wells in the proration battery must be separated and measured as single-phase components, and the resulting total actual battery gas volume (including GEV of condensate) and total actual battery water volume must be prorated back to the wells to determine each well's actual gas and water production.
- Gas wells that meet specific criteria applicable to Southeastern (SE) Alberta Shallow Gas Wells (see *Informational Letter (IL) 93-10: Revised Measurement and Accounting Procedures for Southeastern Alberta Shallow Gas Wells*) may be grouped in a proration battery without specific approval. For those batteries, water volumes do not need to be prorated back to individual wells.
- Gas wells that do not meet the specific criteria applicable to SE Alberta Shallow Gas Wells may only be grouped in a proration battery if the conditions specified in Section 5: Site-specific Deviation from Base Requirements are met or if EUB site-specific approval of an application is obtained.

4.2.3 Gas Gathering System

A facility consisting of pipelines used to move gas production from oil batteries, gas batteries, and/or other facilities to another facility (usually a gas plant) is considered to be a gas gathering system. It may include compressors, line heaters, dehydrators, and other equipment.

Inlet measurement usually consists of the battery or facility group measurement point.

Outlet measurement usually consists of the gas plant inlet measurement.

4.2.4 Gas Plant

A gas plant is a system or arrangement of equipment used for the extraction of H_2S, helium, ethane, NGLs, or other substances from raw gas. It does not include a wellhead separator, treater, dehydrator, or production facility that recovers less than 2 m^3/d of hydrocarbon liquids without using a liquid extraction process (e.g., refrigeration, desiccant). In addition, it does not include an arrangement of equipment that removes small amounts of sulphur (less than 0.1 tonne/day) through the use of nonregenerative scavenging chemicals that generate no H_2S or sulphur dioxide (SO_2).

Inlet separation and measurement are required. However, there are situations where the raw gas has been stripped of its liquid (not recombined downstream) and measured upstream of the plant site. If all streams entering a gas plant on the same gas gathering system are "dry" (the absence of free liquids), the gas plant inlet measurement may consist of the gas gathering system outlet measurement or battery group measurement.

Measurement of all gas deliveries out of the gas plant, such as sales, lease fuel for other facilities, flare and vent gas, acid gas disposition, and any volumes used internally, is required unless otherwise exempted by the EUB.

4.3 Base Requirements for Gas Measurement

4.3.1 System Design and Installation of Measurement Devices

The design and installation of measurement systems must be in accordance with the following.

1) If an orifice meter system is used to measure gas, it must be designed and installed according to the applicable AGA Report #3: *Orifice Metering of Natural Gas and Other Related Hydrocarbon Fluids* (AGA3) listed in Table 4.1 below.

Table 4.1. Orifice meters design requirement (see detailed explanation in this section)

Meter run date of manufacture	Applicable AGA3 (API MPMS 14.3, Part 2) version
Before February 2003	AGA3 1991 or earlier meter run with upstream and/or downstream ID marking – may be reused or relocated for its designed application except to replace a meter where AGA3 2000 spec is required. Non-AGA meter run or run not marked with upstream or downstream ID – grandfathered for the existing volumetric throughput application; if relocated, it must be refurbished to AGA3 (1985) or later specification but cannot be used for sales/delivery point measurement.
After January 2003 (except for sales/delivery point meters measuring sales specification processed gas)	February 1991 or April 2000
All sales/delivery point meters measuring sales specification processed gas manufactured after January 2003	April 2000

When a meter such as a gas plant outlet meter is used to check sales/delivery point measurement and is not normally used to report volumes to the EUB, it does not require AGA3 April 2000 specification. However, when another gas source ties in to the sales pipeline between the check meter and the sales/delivery point meter, the check meter could be used to report volumes to the EUB. In this case, the AGA3 April 2000 specification is required if the meter is manufactured after January 2003, as shown in Figures 4.1 and 4.2, and the operator cannot replace the existing meter run with another meter run manufactured before February 2003 unless it meets the AGA3 April 2000 specification.

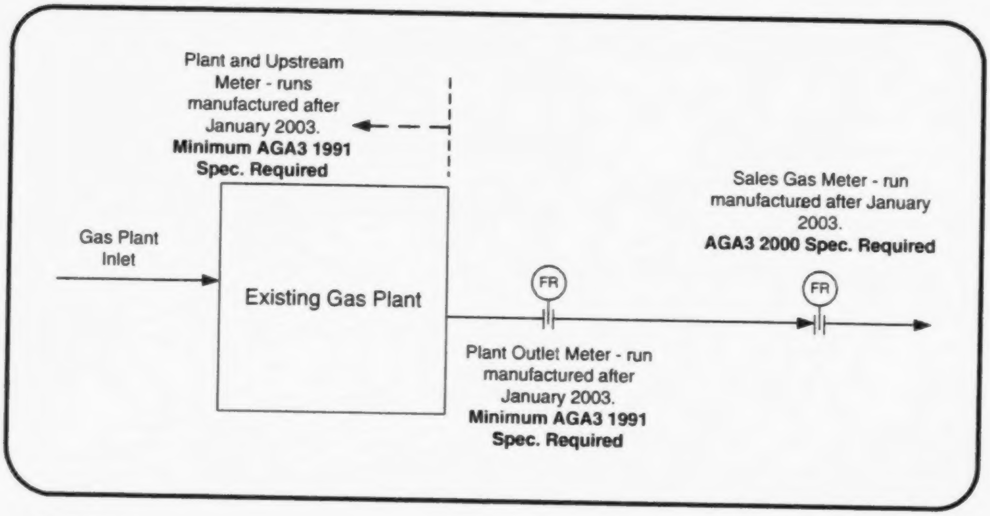

Plant and Upstream Meter - runs manufactured after January 2003.
Minimum AGA3 1991 Spec. Required
Sales Gas Meter - run manufactured after January 2003.
AGA3 2000 Spec. Required
Gas Plant Inlet
Existing Gas Plant
FR
FR
Plant Outlet Meter - run manufactured after January 2003.
Minimum AGA3 1991 Spec. Required

Figure 4.1

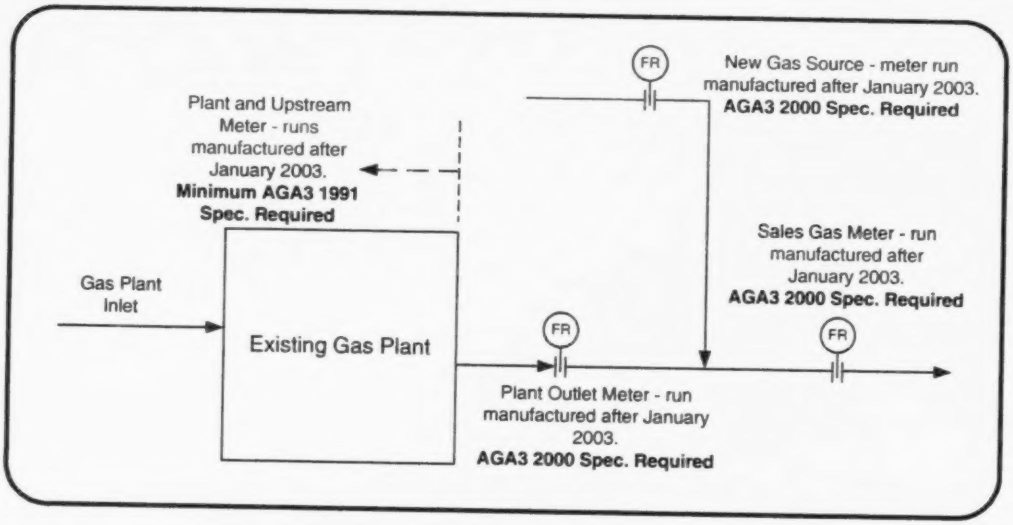

FR
New Gas Source - meter run manufactured after January 2003.
AGA3 2000 Spec. Required
Plant and Upstream Meter - runs manufactured after January 2003.
Minimum AGA3 1991 Spec. Required
Sales Gas Meter - run manufactured after January 2003.
AGA3 2000 Spec. Required
Gas Plant Inlet
Existing Gas Plant
FR
FR
Plant Outlet Meter - run manufactured after January 2003.
AGA3 2000 Spec. Required

Figure 4.2

A permanently marked plate with the following information must be attached to each meter run and maintained in readable condition (not painted over or covered with insulation, etc.) for inspection:

- manufacturer's name
- serial number
- date of manufacture

- average upstream inside diameter (ID) of the meter run at 25.4 mm upstream of the orifice plate in millimetres to one decimal place (or to three decimal places if indicated in inches)
- AGA3 version/year (for new runs only after measurement directive effective date) and/or AGA3 configuration for runs manufactured after January 2003 and not using the April 2000 specification

Meter runs that are manufactured before February 2003 and designed to the AGA3 1991 or earlier specifications complete with the upstream and/or downstream ID markings may be relocated or reused for the application they are designed for.

For existing in-service meter runs that are manufactured before February 2003 and are not designed to the AGA3 2000 or earlier specifications at the time of manufacture or not marked with upstream or downstream ID, nominal pipe ID can be used for flow calculations. These meter runs are grandfathered for the existing volumetric throughput. If new gas volumes are added to such an existing meter run or if a meter run is to be relocated, it must be inspected or refurbished to ensure that it meets the minimum of AGA3 1985 specifications, but it must not be used for sales/delivery point measurement.

The orifice plate must be permanently marked with the plate bore in millimetres to two decimal places (or to three decimal places if indicated in inches), preferably within **6 mm** of the outside edge of the plate, to avoid interfering with normal flow if the marking creates a dent or protrusion on the plate surface.

The chart drive for a circular chart recorder used to measure gas well gas production or group oil battery gas production must not be more than 8 days per cycle unless the exception criteria specified in Section 5: Site-specific Deviation from Base Requirements are met or EUB site-specific approval is obtained. A 24-hour chart drive is required for test gas measurement associated with single oil wells or Class 1 and 2 proration oil wells. An 8-day chart drive may be used for test gas measurement associated with Class 3 and 4 proration oil wells. If the mode of operation causes painting on the chart because of cycling or on/off flows, a 24-hour chart is required for any gas measurement point or EFM must be used.

Chart recorders must be suitably winterized to prevent sensing lines and other piping from freezing and disrupting measurement.

Temperature measurement must be installed according to AGA3 specifications and the temperature must be determined as per Table 4.2 below.

2) Linear metering systems, such as a turbine or vortex meter, used to measure gas must be designed and installed according to the provisions of the 1985 or later editions of the AGA Report #7: *Measurement of Gas by Turbine Meters* (AGA7) or the manufacturer's recommendation.

   Temperature measurement is to be installed according to AGA7 (i.e., between one and five pipe diameter downstream of the meter) or the meter manufacturer's recommendation and the temperature must be determined as per item 8 below.

   For sales/delivery point measurement, the installation must include instrumentation that allows for continuous pressure, temperature, and compressibility corrections either on site (e.g., electronic correctors, electronic flow measurement) or at a later date (e.g., pressure and temperature charts).

3) Rotary metering systems must be designed and installed according to the provisions of the 1992 or later edition of the ANSI B109.3: *Rotary Type Gas Displacement Meters* or the manufacturer's recommendation.

   Install pressure taps not more than 20 pipe diameters upstream and downstream of the meter, to allow for measuring pressure drop across the meter and determining if the meter is over-ranging, if required. It is acceptable for the tap openings to be present within the meter body. The upstream tap must be used for pressure measurement and must be reading the metering pressure (i.e., there must be no pressure restriction between the tap and the meter, such as a regulator).

   The meter must be equipped with a non-reset counter. This can be mechanical or electronic.

   Install temperature measurement according to the meter manufacturer's recommendation or less than 20 pipe diameters downstream of the meter, with no restrictions between the meter and the temperature probe. The temperature must be determined as per item 8 below.

   For sales/delivery point measurement, the installation must include instrumentation that allows for continuous pressure, temperature, and compressibility corrections either on site (e.g., electronic correctors, electronic flow measurement) or at a later date (e.g., pressure and temperature charts).

4) Diaphragm displacement metering systems must be designed and installed according to the provisions of the 1992 or later edition of the ANSI B109.1: *Diaphragm Type Gas Displacement Meters (up to 500 cubic feet/hour capacity)*, or ANSI B109.2: *Diaphragm Type Gas Displacement Meters (over 500 cubic feet/hour capacity)*, and/or the manufacturer's recommendation.

   Other conditions are the same as for the rotary meter above.

5) Venturi or flow nozzle type of metering systems must be installed according to the provisions of the 1991 or later edition of the ISO Standard 5167: *Measurement of fluid flow by means of orifice plates, nozzles and venturi tubes inserted in circular cross-section conduits running full* (ISO 5167) or the meter manufacturer's recommendation. The installation must include instrumentation that allows for continuous pressure, temperature, and compressibility corrections either on site or at a later date.

6) Ultrasonic metering systems must be designed and installed according to the provisions of the 1998 or later editions of *AGA Report No. 9: Measurement of Gas by Multipath Ultrasonic Meters* (AGA9). The installation must include instrumentation that allows for continuous pressure, temperature, and compressibility corrections.

7) Coriolis mass metering systems must be designed and installed according to the provisions of the latest edition of *AGA Report No. 11: Measurement of Natural Gas by Coriolis Meter*. The installation must include instrumentation that allows for continuous temperature correction.

8) If metering systems other than those listed above, such as v-cones or wedge meters, are used to measure gas, they must be installed according to applicable industry accepted standards or the meter manufacturer's recommendation. The installation must include

instrumentation that allows for continuous pressure, temperature, and compressibility corrections (where required) either on site or at a later date.

9) Any electronic gas measurement system must be designed and installed according to the requirements as stated in Section 4.3.3.2. Any EFM system designed and installed in accordance with API MPMS, Chapter 21.1, will meet the audit trail and reporting requirements. However, the performance evaluation is still required in accordance with Section 4.3.3.2. All EFM devices must have a continuous temperature reading for flow calculation.

10) The flowing gas temperature must be measured and recorded according to the table below.

Table 4.2. Temperature reading frequency table for gas measurement

Minimum temperature reading frequency	Criteria or events
Continuous	Sales/delivery points and/or EFM devices
Daily	$> 16.9\ 10^3 m^3/d$
Weekly	$\leq 16.9\ 10^3 m^3/d$
Daily	a) Production (proration) volume testing, or b) Nonroutine or emergency flaring and venting

Note that the temperature-measuring element must be installed near the meter such that it will be sensing the flowing gas stream temperature. That is, the licensee cannot use the surface temperature of the piping or use a thermowell location where there is normally no flow. A meter equipped with a temperature compensation device is considered to have continuous temperature measurement.

4.3.2 Volumetric Calculations

The gas volume calculations comply if the following requirements are met.

- If an orifice meter is used to measure gas, the licensee must use the 1985 or later editions of the AGA3 to calculate the gas volumes.
- If a positive displacement meter or a linear type of meter, such as a turbine, ultrasonic, or vortex meter, is used to measure gas, volumes must be calculated according to the provisions of the 1985 or later editions of the AGA7. Corrections for static pressure, temperature, and compressibility are required.
- If a venturi or flow nozzle type of meter is used to measure gas, volumes must be calculated according to the provisions of the 1991 or later edition of the ISO 5167 or the meter manufacturer's recommended calculation procedures.
- If a Coriolis mass meter is used to measure gas, volumes must be calculated from the measured mass flow and the base density derived from a representative gas sample analysis, including corrections for compressibility. The flowing density measured by the Coriolis mass meter is of insufficient accuracy in a gas application and must not be used to compute volumes.
- If meter types other than those listed above, such as v-cones or wedge meters, are used to measure gas, volumes must be calculated according to the applicable industry accepted standard or the meter manufacturer's recommendation.
- If condensate production from a gas well is required to be reported as a gas equivalent volume, the calculation of the gas equivalent factor must be performed in accordance

with the methodologies outlined in *Directive 046*. The following are the general requirements:

- The gas equivalent volume (GEV) is to be determined based on the latest condensate sample analysis.
- The gas equivalent volume can be determined using the volume fractions, mole fractions, or mass fractions of the condensate analysis.
- The gas equivalent volume can be determined using all of the individual components in the condensate analysis, *or* the C_5 and/or heavier components in the sample can be grouped as C_{5+}, C_{6+}, C_{7+} or other heavier component groups. If the heavier components are grouped, the gas equivalent factor for the grouped components must be calculated using the molecular weight and/or relative density of the grouped components.

- Correction for deviation from the Ideal Gas Laws for compressibility is to be based on equations published in the November 1992, second edition of the AGA Transmission Measurement Committee Report No. 8 (AGA8): *Compressibility Factors of Natural Gas and Other Related Hydrocarbon Gases* or one of the methods listed in the section below. For EFM systems installed before 1994 with software or hardware limitations incompatible with the second edition of AGA8, an earlier version can be used.

Compressibility Factors Used in Gas Volume Calculations

Produced or injected gas volume measurements must be corrected for pressure, temperature, gas composition, and the compressibility of the natural gas.

The AGA8[1] (1992) or Redlich-Kwong with Wichert-Aziz sour gas corrections method should be used for the calculation of the compressibility factors. However, other methods can also be used, provided that the licensee documents the reason for their use. Other methods that could be used are

- Pitzer et al. with Wichert-Aziz sour gas corrections
- Dranchuk, Purvis, Robinson with Wichert-Aziz sour gas corrections (Standing and Katz)
- Dranchuk, Abou-Kassam with Wichert-Aziz sour gas corrections (Starling)
- Hall, Yarborough with Wichert-Aziz sour gas corrections

The EUB will also accept the use of methods other than those mentioned above. If others are used, a suitable reference and comparison to the AGA8 (1992) method or to experimental results and the justification for use must be documented and provided to the EUB for inspection on request.

The AGA8 publication includes several approaches for estimating the properties of natural gas for use in the AGA8 calculation. The full compositional analysis (Detail) method must be used rather than the less accurate partial composition method.

If paper charts are used, the compressibility factor should be calculated at least once for each gas chart cycle. Flow computers and other EFM systems used for gas measurement must calculate and update the compressibility (or supercompressibility) factor at a minimum of once every five minutes, whenever the gas composition is updated, or whenever the average pressure or temperature changes by more than ± 0.5% from the previous average 5-minute value used for calculation.

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[1] See Section 4.4: References for complete bibliographical details for these citations.

Physical Properties of Natural Gas Components

The EUB adopts the physical properties contained in the most recent edition of the Gas Processors Suppliers Association (GPSA) *SI Engineering Data Book*[1] or the Gas Processors Association (GPA) *2145*[1] publication, whichever is the most current. The licensee must ensure that it is using the up-to-date list and, if necessary, update its data. If an EFM system does not have the capability to accept updated physical constants, then the existing set of physical constants may be used; however, that type of EFM system must not be used for measurement of processed gas that meets sales specifications. For standards, such as AGA8, that have imbedded physical constants different in value from those in GPA 2145 or GPSA *SI Engineering Data Book*, changes to such standards are not required unless they are made by the standard association.

4.3.3 Production Data Verification and Audit Trail

General

The field data, records, and any calculations or estimations including EFM relating to EUB-required production data submitted to the Petroleum Registry of Alberta must be kept for inspection on request. The reported data verification and audit trails must be in accordance with the following:

1) When a bypass around a meter is opened or when, for any reason, gas does not reach the meter or the recording device, a reasonable estimate of the unmetered volume must be determined, the method used to determine the estimate must be documented, and a record of the event must be made.

2) A record must be maintained that identifies the gas stream being metered, the measurement devices, and all measurements, inputs, times, and events related to the determination of gas volumes. (See Section 4.3.4: Operations for more detail on orifice chart recorders.) If EFM is used, the required data must be collected and retained according to Section 4.3.3.2.

3) Test records: Any documentation produced in the testing or operation of metering equipment that affects measured volumes. This includes the record containing volume verification and calibration measurements for all secondary and tertiary devices.

4) When a gas metering error is discovered, the licensee of the facility must immediately correct the cause of the error and submit amended monthly production reports to the Petroleum Registry to correct all affected gas volumes.

5) All flared and vented gas must be reported as described in EUB *Directive 007: Production Accounting Handbook*. Incinerated gas must be reported as "flared" gas if an incinerator is used in place of a flare stack. This would not apply to acid gas streams at a gas plant that are incinerated as part of normal operations; in such cases, the incinerated acid gas would be reported as shrinkage, not as flared.

6) Whenever possible, the licensee must report gas as fuel, flared, or vented as occurring at the location where the fuel use, flaring, or venting took place. This will allow industry and EUB staff to match flaring or venting that is observed in the field with that reported. When the fuel usage, flaring, or venting location is within a gas gathering system but is not at a licensed entity,

    a) it should be reported as an activity associated with the closest licensed facility (e.g., compressor) within the gas gathering system, or
    b) if there is no applicable licensed facility within the gas gathering system, it should be reported as an activity associated with the gas gathering system itself.

7) Licensees must not prorate or allocate flared and vented volumes that occur at a facility to other upstream facilities and/or well locations.

8) Dilution gas or gas used to maintain a minimum heating value of the flared or incinerated gas is to be reported as fuel.

9) Production hours for gas wells designed to operate on an on/off cycle basis, such as intermittent timers, pump-off controls, plunger lifts, manual on/off, or pumpjacks, that are "operating normally and as designed on repeated cycles" and where part of the operation involves shutdown of pump equipment and/or shut-in as part of the repeated cycles are to be considered on production even when the wells are not flowing. Physical well shut-ins (not as part of a repeated cycle) and emergency shutdowns (ESDs) are considered down time. The operation personnel have to make a decision based on the operating environment in other situations where the wells are not shut in but may or may not have production.

10) All gas usage, such as for instrumentation, pumps, and heating, must be reported as fuel use on a per-site basis, even if it is vented afterwards. The volume must be measured on a per site basis if over $0.5\ 10^3\ m^3/d$ or may be estimated if not over $0.5\ 10^3\ m^3/d$ (see Figure 1.11).

Electronic Flow Measurement (EFM) for Gas

An EFM system is defined as any flow measurement and related system that collects data and performs flow calculations electronically. If it is part of a Distributed Control System (DCS), Supervisory Control and Data Acquisition system (SCADA) or Programmable Logic Controller system (PLC), only the EFM portion has to meet the requirements in this section. All EFM systems approved under *Guide 34* may continue as approved.

The following systems are not defined as an EFM:

- any meter with an electronic totalizer or pulse counter that does not perform flow calculations (with or without built-in temperature compensation)
- a Remote Terminal Unit (RTU) that transmits any data other than flow data and does not calculate flow

Base Requirements for EFM

If an EFM is used to calculate volumes for EUB accounting purpose, the licensee must be able to verify that it is performing within the EUB target limits defined in this section.

When any parameter that affects the flow calculation is changed, such as orifice plate size, meter factor, fluid analysis, or transmitter range, a signoff procedure or an event log must be set up to ensure that the change is made in the EFM system. All data and reports must be retained for a minimum of 12 months.

Performance Evaluation

A performance evaluation test must be completed within **two weeks** after the EFM is put into service and **immediately** after any change to the computer program or algorithms that affects the flow calculation; it must be documented for EUB audit on request. For existing EFM systems, the EUB encourages licensees to conduct their own performance evaluations. A performance evaluation must be conducted and submitted for EUB audit on request. The EUB considers either one of the following methods acceptable for performance evaluation:

a) Conduct a performance evaluation test on the system by inputting known values of flow parameters into the EFM to verify the volume calculation, coefficient factors, and other parameters. The first **seven** test cases included in this section are for gas orifice meters (AGA3 flow calculations), each with different flow conditions and gas properties. **Test Case 8** is for the AGA7 flow calculation for positive displacement or linear meters. Other manufacturers' recommended equations can also be used to evaluate the EFM performance. The seven AGA3 test cases could also be used to evaluate any compressibility or supercompressibility factors used in other flow calculations using the same gas composition, pressure, and temperature in the calculation as inputs.

b) Evaluate the EFM calculation accuracy with a flow calculation checking program that performs within the target limits for all the factors and parameters listed in the test cases below. A snapshot of the instantaneous flow parameters and factors, flow rates, and configuration information is to be taken from the EFM and input into the checking program. If the instantaneous EFM flow parameters, factors, and flow rates are not updated simultaneously, multiple snapshots may have to be taken to provide a representative evaluation.

Note that some DCS or other control systems have built-in and/or manual input of pressure and temperature for flow calculations. Since the pressure and temperature are not continuously updated, they are not acceptable for EUB accounting and reporting purposes unless EUB approval is obtained.

The volumetric flow rate obtained from a performance evaluation test must agree to within ±0.25% of those recorded on the sample test cases or other flow calculation checking programs. If the ±0.25% limit is exceeded, the EFM must be subjected to a detailed review of the calculation algorithm to resolve the deviation problem. For gas orifice meters, if no AGA3 factor or parameter outputs are available, the acceptable volumetric gas flow rate limit is lowered to ±0.15%.

Test Cases for Verification of Orifice Meter Gas Flow Calculation Programs

The EUB has developed test cases to verify that the EFM system correctly calculates gas flow rates from orifice meters. The seven test cases were calculated on the following basis:

- They are for flange taps only.
- The atmospheric pressure is assumed to be 93.08 kPa(a) (13.5 psia).
- The heaviest carbon component was assumed to be normal heptane.
- The ideal gas relative density was converted to the real gas relative density.
- The same static pressure value is used for pressure taps that are located upstream (U/S) or downstream (D/S) of the orifice plate.
- The AGA3 (1985) results were calculated based on upstream conditions (for both upstream and downstream static pressure tap) in imperial units (the Y_2 factor is also provided for reference). The metric conversion factor for the calculated gas volume is

0.02831685. The compressibility factors were calculated using the Redlich-Kwong (RK) equation with the Wichert-Aziz correction for sour gas.

- The AGA3 (1990) results were calculated using the Detail AGA8 (1992) compressibility factor calculation and using the upstream expansion factor Y_1, as recommended by the AGA3 (1990), Part 1, Section 1.8, even though the pressure tap may be downstream of the orifice plate. (The Y_2 factor is also provided for reference when applicable.)
- The orifice plate material is assumed to be 316 stainless steel and the meter run to be carbon steel at reference temperature of 20°C, isentropic exponent (k) = 1.3, viscosity = 0.010268 centipoise.

Test Case for Verification of AGA7 Gas Flow Calculation Programs

The EUB has developed a test case to verify that the EFM system correctly calculates gas flow rates using the AGA7 equations. The test case was calculated on the following basis:

- The heaviest carbon component was assumed to be normal heptane.
- The compressibility factors were calculated using the Detail AGA8 (1992) or the Redlich-Kwong (RK) equation with the Wichert-Aziz correction for sour gas.

The EUB considers a computer program that uses the AGA3 (1985) equation to be correct if for each of the test cases,

- each of the factors Y, F_a, F_r, and F_{tf} it calculates is within 0.01% of the EUB-determined values;
- the F_b factor it calculates is within 0.1% of the EUB-determined value;
- the F_{gr} factor it calculates is within 0.2% of the EUB-determined value;
- the F_{pv} factor it calculates is within 0.2% of the EUB-determined value;
- the correct base conditions (101.325 kPa[abs] and 15°C) are used in the calculated temperature base factor (F_{tb}) and pressure base factor (F_{pb});
- the gas rate it calculates is within 0.25% of the EUB-determined value.

The EUB considers a computer program that uses the AGA3 (1990) equations to be correct if for each of the test cases,

- both the gas expansion coefficient (Y_1) and the velocity of approach factor (E_v) it calculates are within 0.01% of the EUB-determined values;
- both the discharge coefficient (C_d) and the base compressibility factor (Z_b) it calculates are within 0.1% of the EUB-determined values;
- the compressibility factor at flowing conditions (Z_f) it calculates is within 0.2% of the EUB-determined value;
- the gas rate it calculates is within 0.25% of the EUB-determined value.

The EUB considers a computer program that uses the AGA7 equation to be correct if for the test case,

- both the flowing pressure factor (F_{pm}) and the flowing temperature factor (F_{tm}) it calculates are within 0.1% of the EUB-determined value;
- the compressibility factor (S) it calculates is within 0.2% of the EUB-determined value (both AGA8 and RK factors are provided);
- the correct base conditions (101.325 kPa[abs] and 15°C) are used in the calculated temperature base factor (F_{tb}) and pressure base factor (F_{pb});
- the gas rate it calculates is within 0.25% of the EUB-determined value.

TEST CASE 1 (for AGA3 Flow Calculations)

Gas Analysis

N_2 - 0.0184
CO_2 - 0.0000
H_2S - 0.0260
C_1 - 0.7068
C_2 - 0.1414
C_3 - 0.0674

iC_4 - 0.0081
nC_4 - 0.0190
iC_5 - 0.0038
nC_5 - 0.0043
C_6 - 0.0026
C_7 - 0.0022

Ideal gas relative density - 0.7792

Meter Data (flange taps)

Meter run I.D. - 52.370 mm (2.0618 inches)
Orifice I.D. - 9.525 mm (0.375 inches)

Flow Data (24 hr)

Static pressure - 2818.09 kPa(a) (408.73 psia)
Differential pressure - 10.2000 kPa (40.9897 inches H_2O)
Flowing temperature - 57.0°C (134.600°F)

Gas Volume Result

AGA3 (1985)

Factors	U/S Tap	D/S Tap
F_b	28.4286	28.4286
Y_1	0.9989	0.9989
Y_2	N/A	1.0007
F_{tb}	0.9981	0.9981
F_{gr}	1.1308	1.1308
F_a	1.0012	1.0012
F_r	1.0006	1.0006
F_{pb}	1.0023	1.0023
F_{tf}	0.9351	0.9351
F_{pv}	1.0360	1.0361
C'	31.175	31.179
Q	2.7422	2.7475 10^3 m^3/24 hr

AGA3 (1990)

Factors	U/S Tap	D/S Tap
C_d	0.5990	0.5990
Y_1	0.9989	0.9989
Y_2	N/A	1.0007
E_v	1.0005	1.0005
Z_b	0.9959	0.9959
Z_f	0.9280	0.9277
Q	2.7478	2.7531 10^3 m^3/24 hr

TEST CASE 2 (for AGA3 Flow Calculations)

Gas Analysis

N_2 - 0.0156
CO_2 - 0.0216
H_2S - 0.1166
C_1 - 0.7334
C_2 - 0.0697
C_3 - 0.0228

iC_4 - 0.0044
nC_4 - 0.0075
iC_5 - 0.0028
nC_5 - 0.0024
C_6 - 0.0017
C_7 - 0.0015

Ideal gas relative density - 0.7456

Meter Data (flange taps)

Meter run I.D. - 102.26 mm (4.026 inches)
Orifice I.D. - 47.625 mm (1.875 inches)

Flow Data (24 hr)

Static pressure - 9100.94 kPa(a) (1319.98 psia)
Differential pressure - 11.0000 kPa (44.2046 inches H_2O)
Flowing temperature - 50.0°C (122.0°F)

Gas Volume Result

AGA3 (1985)

Factors	U/S Tap	D/S Tap
F_b	733.697	733.697
Y_1	0.9996	0.9996
Y_2	N/A	1.0002
F_{tb}	0.9981	0.9981
F_{gr}	1.1564	1.1564
F_a	1.0010	1.0010
F_r	1.0002	1.0002
F_{pb}	1.0023	1.0023
F_{tf}	0.9452	0.9452
F_{pv}	1.1072	1.1073
C'	888.905	889.000
Q	145.93	146.03 10^3 m^3/24 hr

AGA3 (1990)

Factors	U/S Tap	D/S Tap
C_d	0.6019	0.6019
Y_1	0.9996	0.9996
Y_2	N/A	1.0003
E_v	1.0244	1.0244
Z_b	0.9967	0.9967
Z_f	0.8098	0.8097
Q	146.08	146.18 10^3 m^3/24 hr

TEST CASE 3 (for AGA3 Flow Calculations)

Gas Analysis

N_2	-	0.0500	iC_4	-	0.0000
CO_2	-	0.1000	nC_4	-	0.0000
H_2S	-	0.2000	iC_5	-	0.0000
C_1	-	0.6000	nC_5	-	0.0000
C_2	-	0.0500	C_6	-	0.0000
C_3	-	0.0000	C_7	-	0.0000

Ideal gas relative density - 0.8199

Meter Data (flange taps)

Meter run	I.D.	-	590.55 mm (23.250 inches)
Orifice	I.D.	-	304.80 mm (12.000 inches)

Flow Data (24 hr)

Static pressure	-	10342.14 kPa(a) (1500.00 psia)
Differential pressure	-	22.1600 kPa (89.0522 inches H_2O)
Flowing temperature	-	60.0°C (140.0°F)

Gas Volume Result

AGA3 (1985)

Factors	U/S Tap	D/S Tap	
F_b	30429.66	30429.66	
Y_1	0.9993	0.9993	
Y_2	N/A	1.0004	
F_{tb}	0.9981	0.9981	
F_{gr}	1.1028	1.1028	
F_a	1.0013	1.0013	
F_r	1.0001	1.0001	
F_{pb}	1.0023	1.0023	
F_{tf}	0.9309	0.9309	
F_{pv}	1.1076	1.1078	
C'	34636.6	34643.21	
Q	8603.19	8614.04	10^3 m^3/24 hr

AGA3 (1990)

Factors	U/S Tap	D/S Tap	
C_d	0.6029	0.6029	
Y_1	0.9993	0.9993	
Y_2	N/A	1.0004	
E_v	1.0375	1.0375	
Z_b	0.9968	0.9968	
Z_f	0.8216	0.8213	
Q	8564.77	8575.48	10^3 m^3/24 hr

TEST CASE 4 (for AGA3 Flow Calculations)

Gas Analysis

N_2 - 0.0029
CO_2 - 0.0258
H_2S - 0.0000
C_1 - 0.9709
C_2 - 0.0003
C_3 - 0.0001

iC_4 - 0.0000
nC_4 - 0.0000
iC_5 - 0.0000
nC_5 - 0.0000
C_6 - 0.0000
C_7 - 0.0000

Ideal gas relative density - 0.5803

Meter Data (flange taps)

Meter run I.D. - 146.36 mm (5.7622 inches)
Orifice I.D. - 88.900 mm (3.500 inches)

Flow Data (24 hr)

Static pressure - 9839.99 kPa(a) (1427.17 psia)
Differential pressure - 6.6130 kPa (26.575 inches H_2O)
Flowing temperature - 22.35°C (72.23°F)

Gas Volume Result

AGA3 (1985)

Factors	U/S Tap	D/S Tap
F_b	2694.965	2694.97
Y_1	0.9998	0.9998
Y_2	N/A	1.0001
F_{tb}	0.9981	0.9981
F_{gr}	1.3116	1.3116
F_a	1.0001	1.0001
F_r	1.0002	1.0002
F_{pb}	1.0023	1.0023
F_{tf}	0.9884	0.9884
F_{pv}	1.0843	1.0843
C'	3790.16	3790.31
Q	501.64	501.82 10^3 m^3/24 hr

AGA3 (1990)

Factors	U/S Tap	D/S Tap
C_d	0.6047	0.6047
Y_1	0.9998	0.9998
Y_2	N/A	1.0001
E_v	1.0759	1.0759
Z_b	0.9980	0.9980
Z_f	0.8425	0.8425
Q	503.44	503.63 10^3 m^3/24 hr

TEST CASE 5 (for AGA3 Flow Calculations)

Gas Analysis

N_2 - 0.0235
CO_2 - 0.0082
H_2S - 0.0021
C_1 - 0.7358
C_2 - 0.1296
C_3 - 0.0664

iC_4 - 0.0088
nC_4 - 0.0169
iC_5 - 0.0035
nC_5 - 0.0031
C_6 - 0.0014
C_7 - 0.0007

Ideal gas relative density - 0.7555

Meter Data (flange taps)

Meter run I.D. - 154.05 mm (6.0650 inches)
Orifice I.D. - 95.250 mm (3.750 inches)

Flow Data (24 hr)

Static pressure - 2499.9 kPa(a) (362.58 psia)
Differential pressure - 75.000 kPa (301.395 inches H_2O)
Flowing temperature - 34.0°C (93.2°F)

Gas Volume Result

AGA3 (1985)

Factors	U/S Tap	D/S Tap
F_b	3111.24	3111.24
Y_1	0.9894	0.9897
Y_2	N/A	1.0044
F_{tb}	0.9981	0.9981
F_{gr}	1.1485	1.1485
F_a	1.0005	1.0005
F_r	1.0001	1.0001
F_{pb}	1.0023	1.0023
F_{tf}	0.9695	0.9695
F_{pv}	1.0382	1.0394
C'	3561.90	3567.34
Q	800.22	813.37 10^3 m^3/24 hr

AGA3 (1990)

Factors	U/S Tap	D/S Tap
C_d	0.6042	0.6041
Y_1	0.9894	0.9897
Y_2	N/A	1.0044
E_v	1.0822	1.0822
Z_b	0.9962	0.9962
Z_f	0.9240	0.9217
Q	799.83	813.00 10^3 m^3/24 hr

TEST CASE 6 (for AGA3 Flow Calculations)

Gas Analysis

N_2 - 0.0268
CO_2 - 0.0030
H_2S - 0.0000
C_1 - 0.6668
C_2 - 0.1434
C_3 - 0.1023

iC_4 - 0.0123
nC_4 - 0.0274
iC_5 - 0.0000
nC_5 - 0.0000
C_6 - 0.0180
C_7 - 0.0000

Ideal gas relative density - 0.8377

Meter Data (flange taps)

Meter run I.D. - 52.500 mm (2.0669 inches)
Orifice I.D. - 19.050 mm (0.750 inches)

Flow Data (24 hr)
Static pressure - 2506.33 kPa(a) (363.50 psia)
Differential pressure - 17.0500 kPa (68.5171 inches H_2O)
Flowing temperature - 7.2°C (44.96°F)

Gas Volume Result

AGA3 (1985)

Factors	U/S Tap	D/S Tap
F_b	115.138	115.138
Y_1	0.9978	0.9978
Y_2	N/A	1.0012
F_{tb}	0.9981	0.9981
F_{gr}	1.0902	1.0902
F_a	0.9996	0.9996
F_r	1.0003	1.0003
F_{pb}	1.0023	1.0023
F_{tf}	1.0148	1.0148
F_{pv}	1.0708	1.0714
C'	136.15	136.22
Q	14.602	14.660 10^3 m^3/24 hr

AGA3 (1990)

Factors	U/S Tap	D/S Tap
C_d	0.6005	0.6005
Y_1	0.9978	0.9978
Y_2	N/A	1.0012
E_v	1.0088	1.0088
Z_b	0.9951	0.9951
Z_f	0.8588	0.8578
Q	14.687	14.746 10^3 m^3/24 hr

TEST CASE 7 (for AGA3 Flow Calculations)

Gas Analysis

N_2 - 0.0070
CO_2 - 0.0400
H_2S - 0.0000
C_1 - 0.8720
C_2 - 0.0340
C_3 - 0.0250

iC_4 - 0.0062
nC - 0.0090
iC_5 - 0.0052
nC_5 - 0.0016
C_6 - 0.0000
C_7 - 0.0000

Ideal gas relative density - 0.6714

Meter Data (flange taps)

Meter run I.D. - 52.500 mm (2.0669 inches)
Orifice I.D. - 12.70 mm (0.50 inches)

Flow Data (24 hr)
Static pressure - 299.92 kPa(a) (43.50 psia)
Differential pressure - 6.3455 kPa (25.5 inches H_2O)
Flowing temperature - 1.67°C (35°F)

Gas Volume Result

AGA3 (1985)

Factors	U/S Tap	D/S Tap	
F_b	50.523	50.523	
Y_1	0.9933	0.9935	
Y_2	N/A	1.0039	
F_{tb}	0.9981	0.9981	
F_{gr}	1.2190	1.2190	
F_a	0.9994	0.9994	
F_r	1.0018	1.0018	
F_{pb}	1.0023	1.0023	
F_{tf}	1.0250	1.0250	
F_{pv}	1.0035	1.0036	
C'	63.013	63.029	
Q	1.4263	1.4416	10^3 m^3/24 hr

AGA3 (1990)

Factors	U/S Tap	D/S Tap	
C_d	0.6006	0.6006	
Y_1	0.9933	0.9934	
Y_2	N/A	1.0039	
E_v	1.0017	1.0017	
Z_b	0.9973	0.9973	
Z_f	0.9905	0.9903	
Q	1.4335	1.4489	10^3 m^3/24 hr

TEST CASE 8 (for AGA7 Flow Calculations)

Gas Analysis

N_2 - 0.0268
CO_2 - 0.0030
H_2S - 0.0000
C_1 - 0.6668
C_2 - 0.1434
C_3 - 0.1023
iC_4 - 0.0123
nC_4 - 0.0274
iC_5 - 0.0000
nC_5 - 0.0000
C_6 - 0.0180
C_7 - 0.0000

Flow Data (24 hr)

Uncorrected volume - 128.0 $10^3 m^3$
Static pressure - 2506.33 kPa(a) (363.50 psia)
Flowing temperature - 7.2°C (44.96°F)

Gas Volume Result

AGA7 (Volumetric Flow)
Factors

F_{pm}	24.6784
F_{pb}	1.0023
F_{tm}	1.0298
F_{tb}	0.9981

Using AGA8 compressibility equations,

S	1.1588
Q	3770.9 10^3 m^3/24 hr

Using RK compressibility equations,

S	1.1467
Q	3731.6 10^3 m^3/24 hr

EFM Reports

The required information on each report must be stored using electronic/magnetic (not necessarily on the EFM) or printed media and can exist individually on different formats or reports and generated on demand for audit, as follows:

- **Daily** for daily report required data
- **Monthly** for monthly report required data
- Event and alarm logs at regular intervals before information is overwritten
- Meter reports generated on request for audit

The Daily Report

The daily report must include

- meter identification
- daily accumulated flow, with indicating flags for estimated flows made by the system or by the operation personnel and alarms that have occurred for over-ranging of end devices
- hours on production or hours of flow (specify)
- flow data audit trail – include at least one of the following:
    - instantaneous values for flow rate, differential pressure (if applicable), static pressure, and temperature taken at the same time each day, or
    - average daily values for differential pressure (if applicable), static pressure, and temperature, or
    - hourly accumulated flow rate and average hourly values for differential pressure (if applicable), static pressure, and temperature

Existing EFM systems that predate *Guide 34* approvals and do not have any of the above audit trail capabilities, and cannot develop the capability due to system limitations, should be evaluated for upgrading, especially when new production is tied into the facilities. The EUB may request upgrades, where audit/inspection results indicate they are warranted.

The Monthly Report

This report is for the entire system, providing data for each measurement point. It is to contain the following at each measurement point as applicable:

- monthly cumulative flow
- flags indicating any change made to flow volumes
- total hours on production or hours of flow (specify)

The Meter Report

The meter report details the configuration of each meter and flow calculation information. These values are used as part of the "audit trail" to confirm that the flow calculation is functioning correctly. Without them there is no way of verifying the accuracy of the system. The meter report must include the following as applicable and be produced on demand:

1) Instantaneous flow data
    - Instantaneous flow rate
    - Instantaneous static pressure
    - Instantaneous differential pressure
    - Instantaneous flowing temperature
    - Instantaneous relative density (if live)
    - Instantaneous compressibility (if live)
    - Instantaneous gas component (if live)

  - Optional: instantaneous (AGA3) factors (see the orifice meter test cases above for output information)

2) Current configuration information for differential meters or other types of meters, whichever are applicable:
   - meter identification
   - date and time
   - contract hour
   - atmospheric pressure
   - pressure base (unless fixed)
   - temperature base (unless fixed)
   - meter tube reference inside diameter
   - orifice plate reference bore size
   - static pressure tap location
   - orifice plate material
   - meter tube material
   - calibrated static pressure range
   - calibrated differential pressure range
   - calibrated temperature range
   - high/low differential cutoff
   - relative density (if not live)
   - compressibility (if not live)
   - gas components (if not live)
   - meter factor and/or k factor
   - effluent correction factor

The Event Log

This log is used to note and record exceptions and changes to the flow parameter, configuration, programming, and database affecting flow calculations, such as, but not limited to,

- orifice size change
- transmitter range change
- date of gas/liquid analysis update
- algorithm changes
- meter factor, k factor, or effluent correction factor changes
- other manual inputs

The Alarm Log

The alarm log includes any alarms that may have an effect on the measurement accuracy of the system. The time of each alarm condition and the time of clearing of each alarm must be recorded. Alarms to be reported must include, but are not limited to,

- master terminal unit failures
- remote terminal unit failures
- communication failures
- low-power warning

- high differential pressure (for differential measurement devices)
- high/low volumetric flow rate (for other types of measurement)
- over-ranging of end devices

4.3.4 Operations—Base Requirements for Acceptable Gas Measurement and Reading of Gas Charts

4.3.4.1 General Operations

- Full port shutoff valves must be used for metering taps for differential pressure devices.
- Sharing of metering taps by multiple differential pressure devices is not allowed if it will cause increased measurement uncertainty, such as painting or spiking charts, or under pulsation conditions.
- A separate set of valve manifolds must be used for each device.
- A minimum of 9.53 mm tubing must be used to connect metering devices.

4.3.4.2 Chart Operations

Field operation personnel **must** ensure that

- the meter location is properly identified on the chart;
- the chart is correctly dated;
- the on and off chart times are recorded on the chart to the nearest quarter hour if not actual;
- the correct orifice plate and line size are recorded on the chart;
- the time (to the nearest quarter hour) of any orifice plate change is indicated on the chart, along with the new orifice plate size;
- it is noted on the charts if the differential, pressure, or temperature range of the recorder has been changed or if they are different from the ranges printed on the chart;
- a copy of the chart calibration report is kept on site or readily available for on-site inspection if it is a manned facility;
- the flowing gas temperature is recorded on the chart in accordance with Table 4.2 above;
- proper chart reading instructions are provided when the pen fails to record because of sensing line freezing, clock stoppage, pens out of ink, overlapping traces, or other reasons (draw in the estimated traces, request to read as average flow for the missing period, or provide estimate of the differential and static); and
- any data or traces that require correction must not be covered over or obscured by any means.

Field operation personnel **should** ensure that

- a notation is made on the chart with regard to whether or not the meter is set up for atmospheric pressure (for square root charts);
- the accuracy of the meter clock speed is checked and the chart reader is instructed accordingly of any deviations;
- the differential pen is zeroed once per chart cycle;
- differential pen recordings are at 33% or more within the chart range whenever possible;
- static pen recordings are at 20% or more within the chart range whenever possible;
- when there is a painted differential band, instructions are provided as to where it should be read. There are various ways to read a painted chart:

  - If the differential pen normally records at the top of the painted band but spikes quickly down and up during separator dump cycles, it is reasonable to read the differential near the top of the band (or vice versa).
  - If the differential pen is in constant up and down motion, it is reasonable to read the differential at the root mean square (RMS) of the band or in a sine wave motion alternating between the top and bottom of the painted area.
- The pen trace colours conform to the industry-accepted practice (RED for differential, BLUE for static, and GREEN for temperature); however, any colour may be used, provided the colour used is documented.

4.3.4.3 EUB Site-Specific Requests

If an inspection of a measurement device or of procedures reveals unsatisfactory conditions that significantly reduce measurement accuracy, the EUB inspector or auditor will direct in writing that the licensee implement changes to improve measurement accuracy, and this direction will become a condition of operation for that facility or facilities. Examples of conditions applicable to orifice chart recorders are as follows:

- thick pen traces that will cause excessive error when reading the traces
- painting traces
- differential or static pens recording too low on the chart—in some cases, this cannot be avoided because of low flow rate, high shut-in pressure, and equipment or operating pressure range limitations.

4.3.4.4 Chart Reading

The chart integrator/planimeter operator **must** ensure the following:

- Visible gaps between the integrator/planimeter traces and chart traces are minimized.
- The counter is read correctly.
- The integrator is calibrated periodically and after each change of pens.
- The correct integrator or square root planimeter constants are noted.
- The correct integrator setback is recorded.
- The correct coefficient, using all of the required factors, is recorded.

4.3.4.5 A new chart reading technology guideline is under development and will be added to this directive when ready.

4.3.5 Exceptions

Gas in Solution with Oil Volumes under Pressure

In some cases a gas volume must be determined where the gas is dissolved in an oil volume under pressure, and there is no opportunity to measure the gas volume prior to it being commingled with other gas volumes. In that case, the gas volume may be determined by estimation, regardless of its daily volume rate. An example of such a gas volume is the gas held in solution with oil volumes leaving a test separator at an oil proration battery, where the test oil volumes are combined with production from other wells downstream of the test separator. The purpose of estimating the gas in solution is to determine the total gas produced by a well during a production test, since the gas volume measured by the test gas meter will not include the gas that is still in solution with the test oil volume.

A single gas-in-solution (GIS) factor may be determined and used to estimate the gas volume held in solution with the oil stream for each oil stream where the production sources (producing formation) are the same and test separator operating conditions are similar. Additional GIS factors are required for wells in the battery that produce from different formations and where other test separators operate at different pressure and/or temperature conditions. Licensees should also consider determining seasonal GIS factors where ambient temperature differences may significantly affect the factors or when operating conditions change significantly.

The GIS factor may be determined by one of the following applicable tests/procedures:

- A 24-hour test may be conducted such that the production from a well (or group of wells) is directed through the test and group separation/treating equipment, with all other wells shut in or directed around the equipment. The total volume of gas released from the oil after it leaves the test separator must be measured; this volume divided by the stock tank volume of oil determined at the test separator provides a GIS factor.
- A sample of oil taken under pressure containing the gas in solution that will be released when the oil pressure is reduced may be submitted to a laboratory where a pressure-volume-temperature (PVT) analysis can be conducted. The analysis must be based on the actual pressure and temperature conditions that the oil sample would be subjected to downstream of the sample point, including multiple stage flashing. The GIS factor is calculated based on the volume of gas released from the sample and the volume of oil remaining at the end of the analysis procedure.
- A sample of oil taken under pressure containing the gas in solution that will be released when the oil pressure is reduced may be submitted to a laboratory where a compositional analysis can be conducted. A computer simulation program may be used to determine the GIS factor based on the compositional analysis.
- A "rule of thumb" estimate (0.0257 m^3 of gas/m^3 of oil/kPa of pressure drop) may be used as the GIS factor for conventional light-medium oil production until a more accurate, specific GIS factor is determined. It may be used on a continuous basis, without the need for determining a more accurate GIS factor, if well oil production rates do not exceed 2 m^3/d or if all battery gas production is vented or flared.
- Other methods listed in the Canadian Association of Petroleum Producers (CAPP) *Guide for Estimation of Flaring and Venting Volumes from Upstream Oil and Gas Facilities* may be used.

Gas Produced in Association with Conventional Oil Well and Gas Well Production

If a gas stream volume associated with conventional oil well or gas well production does not exceed 0.5 10^3 m^3 per day at any given measurement/disposition point, the volume may be determined by estimation instead of measurement. Examples of the gas streams that may be estimated if the daily volume limitation is not exceeded include well test gas, battery group gas, single-well battery gas, fuel gas used on a per site basis, and oil/condensate tank vented gas. A gas stream that must be measured regardless of daily volume is dilution gas added to an acid gas stream to ensure complete combustion (due to the importance of accurately determining those volumes).

Initial qualification of gas streams where volumes may be estimated can be based on existing historical data or determined by conducting one of the applicable tests/procedures in Section 4.3.5.4. Qualifying gas volumes may be estimated by using a gas-oil-ratio (GOR) factor if gas volume estimates will vary in conjunction with oil volumes or by using an hourly rate if gas volumes are not dependent upon oil volumes. These factors must be updated annually to confirm continuing eligibility for estimation and to update the factors used to estimate gas volumes. The factors must also be updated immediately following any operational changes that could cause the factors to change. Licensees should also consider determining seasonal GOR factors if ambient temperature differences may significantly affect the factors. Updated factors may be determined by one of the applicable tests/procedures described below.

Gas Produced in Association with Heavy Crude Oil/Crude Bitumen Production

Within Designated Oil Sands Areas

For single-well batteries, a GOR factor may be used to determine total gas production. If suitable reservoir information is available, it may be used to determine the GOR factor for estimating gas production at new wells until the gas production stabilizes. In the absence of suitable reservoir information, monthly GOR tests must be conducted to determine the GOR factor until gas production stabilizes. Once gas production has stabilized, the GOR factor must be updated annually if the GOR exceeds 100 m^3/m^3 and every three years if the GOR is ≤100 m^3/m^3. The GOR factor must also be updated immediately following any operational changes that could cause the factor to change. Licensees should also consider determining seasonal GOR factors if ambient temperature differences may significantly affect the factors.

If associated gas from a number of wells is connected by flow line to a central battery and the total battery gas volumes do not exceed 2 10^3 m^3 per day, a GOR factor may be used to determine total battery gas production and individual well gas production. Initial qualification may be based on existing historical data or on an initial GOR test. The GOR factor must be updated annually to confirm continuing eligibility for estimation and to update the factor used to estimate gas volumes. The GOR factor must also be updated immediately following any operational changes that could cause the factor to change. Licensees should also consider determining seasonal GOR factors if ambient temperature differences may significantly affect the factors. Initial and updated factors may be determined by any of the applicable tests/procedures described below.

Outside Designated Oil Sands Areas

If gas volumes associated with heavy oil/bitumen production do not exceed 2 10^3 m^3 per day at any given measurement point, those volumes may be determined by estimation instead of measurement. Examples of the gas streams that may be estimated if the daily volume limitation is not exceeded include well test gas, battery group gas, single-well battery gas, fuel gas, and oil tank vented gas. Initial qualification of gas streams where volumes may be estimated can be based on existing historical data or determined by conducting one of the applicable tests/procedures in Section 4.3.5.4. Qualifying gas volumes may be estimated by using a GOR factor if gas volume estimates will vary in conjunction with oil volumes or by using an hourly rate if gas volumes are not dependent upon oil volumes. The GOR factor must be updated in accordance with the frequency table below to confirm continuing eligibility for estimation and to update the factor used to estimate gas volumes. The factors must also be updated immediately following any operational changes that could cause the factors to change. Licensees should also consider determining seasonal GOR factors if ambient temperature differences may significantly affect the factors.

GOR Test Frequency Requirements

Gas rate (10^3 m^3/d)	GOR test frequency
≤ 0.5	annually
> 0.5 but ≤ 1.0	semi-annually
> 1.0 but ≤ 2.0	monthly

Initial and updated factors may be determined by any of the applicable tests/procedures described below.

Methods for Determining Factors/Rates Used in Estimating Gas Volumes

If gas volumes will be estimated using a GOR:

- A 24-hour test may be conducted such that all the applicable gas and oil volumes produced during the test are measured (including vented gas). The gas volume is to be divided by the oil volume to result in the GOR factor.
- A sample of oil taken under pressure containing the gas in solution that will be released when the oil pressure is reduced may be submitted to a laboratory where a PVT analysis can be conducted. The analysis must be based on the actual pressure and temperature conditions the oil sample would be subjected to downstream of the sample point. The GOR factor will be calculated based on the volume of gas released from the sample and the volume of oil remaining at the end of the analysis procedure.
- A sample of oil taken under pressure containing the gas in solution that will be released when the oil pressure is reduced may be submitted to a laboratory where a compositional analysis can be conducted. A computer simulation program may be used to determine the GOR based on the compositional analysis.
- Other methods listed under the Canadian Association of Petroleum Producers (CAPP) *Guide for Estimation of Flaring and Venting Volumes from Upstream Oil and Gas Facilities* may be used

If gas volumes will be estimated using an hourly rate:

- A meter may be used to measure the gas stream for a minimum of one hour. The gas volume measured during this test may be used to determine the hourly rate that will be used to estimate gas volumes.
- If applicable, such as for fuel gas volumes, the hourly rate may be determined based on the equipment manufacturer's stated gas consumption rates and the actual operating conditions.

Example Calculations for Estimating Gas Volumes Using GOR and GIS Factors

Determination of Total Produced Gas for a Single-Well Oil Battery

Figure 4.3 depicts a single-well battery where a three-phase separator is used to separate oil, gas, and water production from a well. The oil in the separator is under pressure until it is directed to the storage tank, which is at atmospheric pressure (zero kPa gauge). When the oil pressure drops at the tank, the GIS within the oil will be released. The gas leaving the separator in this example is measured, while the GIS released at the tank is estimated using a GOR factor. Total gas production from the well is determined by adding the measured gas and the GIS released at the oil storage tank.

If a single-well battery uses a two-phase separator, the procedure for determining total gas production is the same as for a three-phase separator.

If the gas production rate meets the qualifying criteria for estimation and all production from the well produces directly to a tank without using a separator, the total gas production may be determined by using only a GOR factor.

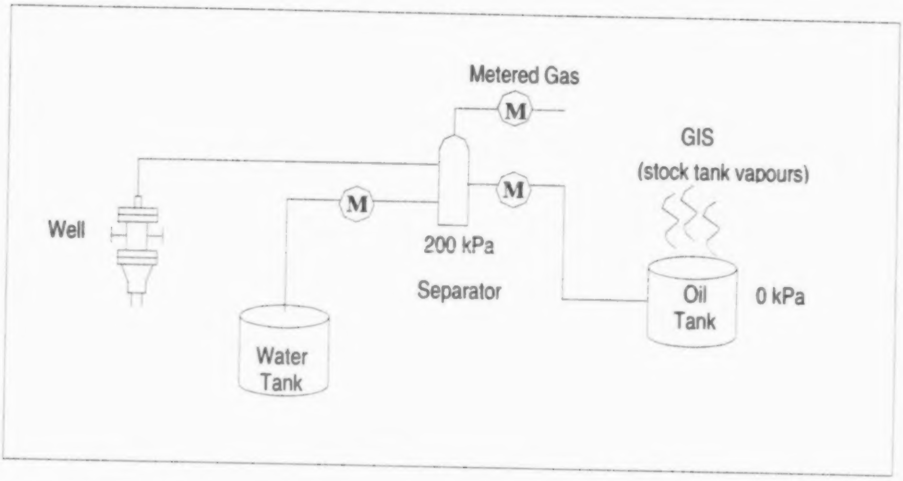

Figure 4.3. Single-well oil battery example

Sample Calculation: Total Gas Volume at a Single-Well Battery (Figure 4.3)

Monthly well data (hypothetical) given for this example:

Gas meter volume = 96.3 10^3 m^3 (from chart readings)
Oil meter volume = 643.3 m^3 (from meter or tank gauging)
Pressure drop = 200 kPa
GOR factor = 6.37 m^3 gas/m^3 oil or 0.03185 m^3 gas/m^3 oil/kPa pressure drop (determined using a method other than the "rule of thumb")

Step 1: Calculate GIS volume =
6.37 m^3/m^3 x 643.3 m^3 = 4097.8 m^3 = 4.10 10^3 m^3
or
0.03185 m^3/m^3/kPa x 643.3 m^3 x 200 kPa = 4097.8 m^3 = 4.10 10^3 m^3

Step 2: Calculate the total battery gas production for the month =
96.3 10^3 m^3 + 4.1 10^3 m^3 = 100.4 10^3 m^3

Note that total reported battery gas production is to be rounded to one decimal place.

Determination of Total Produced Gas for an Oil Proration Battery

Figure 4.4 depicts a multiwell oil proration battery where production testing of individual wells is done by directing individual well production through a test separator at the main battery site or through a test separator at a satellite facility located away from the main battery site.

In this example, the oil, gas, and water leaving the test separator at the satellite are recombined with the satellite group production and directed to the group separation and measurement equipment at the main battery site. The oil and water leaving the test separator at the main battery site are recombined with the battery group production, but the gas leaving the test separator recombines with the group gas downstream of the group gas measurement point. The oil in the group separator is under pressure until it is directed to the storage tank, which is at atmospheric pressure (zero kPa gauge). When the oil pressure drops at the tank, the GIS with the oil will be released.

The total gas production at the battery will be the sum of all the measured test gas at the battery site, the measured group gas at the battery, and the GIS released at the oil storage tank.

Trucked oil volumes received at the battery must not be included with the total battery oil volume when determining the GIS released at the oil storage tank.

At some facilities a vapour recovery unit (VRU) may be installed to collect any GIS that may be released at the oil storage tank. If the VRU is equipped with a meter or the recovered gas is directed through the group gas meter, a GIS calculation will not be required because the measured VRU gas will either be added to or included in the other measured gas volumes.

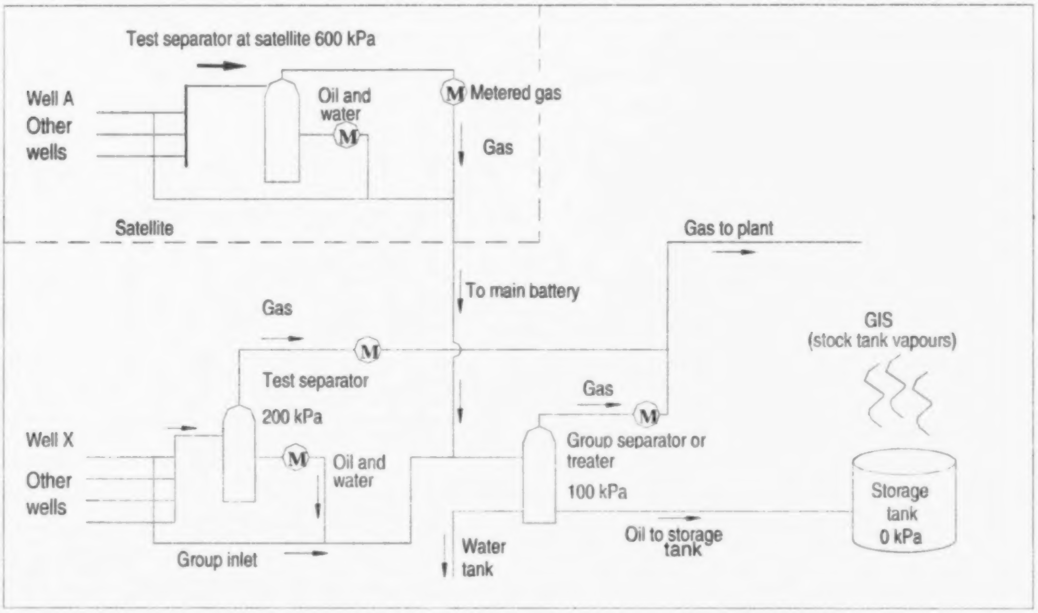
Test separator at satellite 600 kPa
Well A
Other wells
Oil and water
M
Metered gas
Gas
Satellite
Gas to plant
To main battery
Gas
M
Test separator
200 kPa
GIS
(stock tank vapours)
Gas
M
Well X
Other wells
M
Oil and water
Group separator or treater
100 kPa
Storage tank
0 kPa
Oil to storage tank
Water tank
Group inlet

Figure 4.4. Multiwell oil battery example

Sample Calculation: Total Gas Production at the Oil Proration Battery (Figure 4.4)

Monthly battery data (hypothetical) given for this example:
Oil production at the proration battery = 745.0 m^3 for the month (from meter and/or tank gauging)

Total test gas measured at the battery site = 30.0 $10^3 m^3$ (from chart readings)
Measured group gas production = 67.4 $10^3 m^3$ (from chart readings)
Pressure drop from the group vessel to oil storage tank = 100 kPa
GOR factor = 3.99 m^3 gas /m^3 oil or 0.0399 m^3/m^3/kPa (determined using a method other than the "rule of thumb")

Step 1: Calculate the GIS volume =
3.99 m^3/m^3 x 745.0 m^3 = 2972.6 m^3 = 2.97 $10^3 m^3$
or
0.0399 m^3/m^3/kPa x 745 m^3 x 100 kPa = 2972.6 m^3 = 2.97 $10^3 m^3$

Step 2: Calculate the total produced gas volume for the battery =
67.4 10^3 m^3 +30.0 10^3 m^3 + 2.97 10^3 m^3 = 100.4 10^3 m^3

Note that total reported battery gas production is to be rounded to one decimal place.

Determination of Individual Well Test Gas for an Oil Proration Battery

Figure 4.4 depicts a multiwell oil proration battery where production testing of individual wells is done by directing individual well production through a test separator at the main battery site or through a test separator at a satellite facility located away from the main battery site. In either case, the oil leaving the test separator is under pressure and will be subjected to two stages of pressure drop—one at the group separator and one at the storage tank. The total gas produced by a well during a test will be the sum of the gas measured as it leaves the test separator and the GIS that will evolve from the test oil volume after leaving the test separator. In the example, the test separators at the battery and satellite operate at significantly different pressures, and the oil leaving the test separator at the satellite will contain more GIS than the oil leaving the test separator at the battery.

Sample Calculation: Test Gas Production for Wells in the Satellite (Figure 4.4)

Satellite test data (hypothetical) given for this example for well "A":
Measured test oil = 7.22 m^3 (from oil meter)
Measured test gas = 1.27 10^3 m^3 (from chart readings)
GIS factor = 25.62 m^3 gas/m^3 oil or 0.0427 m^3 gas/m^3 oil/kPa pressure drop (combined GIS for both stages of pressure drop from test pressure at 600 kPa to group pressure at 100 kPa to oil storage tank pressure at atmospheric pressure or zero kPa gauge, determined using a method other than the "rule of thumb")

Step 1: Calculate the GIS volume =

0.0427 m^3/m^3/kPa x 7.22 m^3 x 600 kPa = 185.0 m^3 = 0.19 10^3 m^3
or
25.62 m^3/m^3 x 7.22 m^3 = 185.0 m^3 = 0.19 $10^3$$m^3$

Step 2: Calculate the total test gas produced for well "A" for this test =
1.27 10^3 m^3 + 0.19 10^3 m^3 = 1.46 10^3 m^3

Note that test gas volumes must be determined to two decimal places (in 10^3 m^3).

Sample Calculation: Test Gas Production for Wells in the Battery (Figure 4.4)

Battery test data (hypothetical) given for this example for well "X":
Measured test oil = 3.85 m^3 (from oil meter)
Measured test gas = 2.33 10^3 m^3 (from chart readings)
GIS factor = 7.90 m^3 gas/m^3 oil or 0.0395 m^3 gas/m^3 oil/kPa pressure drop (combined GIS for both stages of pressure drop from test pressure at 200 kPa to group pressure at 100 kPa to oil storage tank pressure at atmospheric pressure or zero kPa gauge, determined using a method other than the "rule of thumb")

Step 1: Calculate the GIS volume =
0.0395 m^3/m^3/kPa x 3.85 m^3 x 200 kPa = 30.4 m^3 = 0.03 10^3 m^3
or
7.90 m^3/m^3 x 3.85 m^3 = 30.4 m^3 = 0.03 10^3 m^3

Step 2: Calculate the total test gas produced for well "X" for this test =
$2.33\ 10^3\ m^3 + 0.03\ 10^3\ m^3 = 2.36\ 10^3\ m^3$

Note that test gas volumes must be determined to two decimal places (in $10^3\ m^3$).

4.4 References

American Gas Association Transmission Measurement Committee Report No. 8 (AGA8), November 1992. *Compressibility and Supercompressibility for Natural Gas and Other Hydrocarbon Gases.*

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Yarborough, L., and Hall, K.R., "How to Solve Equation of State for Z-Factors," *The Oil and Gas Journal*, February 18, 1974, pp. 86-88.

5 Site-specific Deviation from Base Requirements

Section 1: Standards of Accuracy states that a licensee may deviate from the EUB's minimum measurement, accounting, and reporting requirements without specific approval if no royalty, equity, or reservoir engineering concerns are associated with the volumes being measured and the licensee is able to demonstrate that the alternative measurement equipment and/or procedures will provide measurement accuracy within the applicable uncertainties. This section describes situations where a licensee may deviate from the minimum requirements without EUB approval, provided that specific criteria are met. Licensees may also apply for approval to deviate from the minimum requirements if the specific criteria are not met; this section indicates what information must be included in such an application. If these exceptions or approvals are in use, EUB inspectors and auditors will review the licensee's records for demonstrated compliance with the criteria specified in this section or in the applicable approval.

Specialized Terminology Defined

Common Ownership	All wells in a battery belong to the same working interest participant, or if there is more than one working interest participant, each working interest participant has the same percentage interest in each well in the battery.
Common Crown or Freehold Royalty	When all the wells in a battery are produced under Crown mineral leases, the Crown receives the same royalty rate for each well, or when under leases granted by one Freehold mineral holder, the Freehold mineral holder receives the same royalty rate for each well. If there is more than one Freehold mineral holder for the wells in a battery, the total royalty rate for each well is the same.
Measured Gas Source(s)	These are single-phase measured gas source(s) downstream of separation and removal of liquids. This also includes the gas equivalent volume (GEV) of measured condensate if the condensate is recombined with the gas downstream of the separator.
Measured Oil	Oil is measured using equipment and/or procedures meeting delivery point measurement uncertainty limits. For emulsion, the delivery point measurement uncertainty limits apply to the total volume determination only.

5.1 Site-specific Exceptions

Deviation from base measurement, accounting, and reporting requirements is allowed without submission of an application to the EUB, provided that all the initial qualifying criteria listed under the subsequent "Exception" sections are met.

Initial Qualifying Criteria—These criteria (detailed in subsequent sections) must be met to qualify for the exception. If the initial qualifying criteria have been met and the exception is implemented, it may remain in place indefinitely, as long as it does not meet any of the revocation clauses and no physical additions to the facility are made (e.g., new wells or zones). If additions or changes are made to the battery or facility, the initial qualifying criteria must be met for all the wells or zones added to the battery or facility for the exception to remain in place. If the licensee anticipates that physical additions may not meet the initial qualifying criteria, the licensee may reconfigure the facility to meet base measurement, accounting, and reporting requirements or submit an application for site-specific approval of deviation from the base requirements. Approval must be in place prior to implementation. Submission of an application does not guarantee that an approval will be granted.

Documentation Requirement—The licensee must retain the data and documentation to support the initial qualifying criteria and the last three testing records (if applicable) for as long as the exception is in place. The EUB may revoke an exception if an audit or inspection reveals a lack of adequate supporting data or documentation. If the licensee cannot provide documentation requested for EUB audit within 30 days, the licensee will be required to meet applicable EUB base measurement requirements immediately. Alternatively, at the EUB's discretion, the licensee may propose a plan to comply with the EUB exception requirements within an EUB-approved time period.

5.2 Site-specific Approval Applications

If the exception criteria cannot be met or if a specific situation is not covered in this section, the licensee may be allowed to deviate from base measurement, accounting, and reporting requirements upon approval of an application submitted to the EUB Production Operations Section.

Approvals will remain in place indefinitely, including after transfer of the facility to another licensee, provided that conditions specified in the approval are met. If an EUB audit or inspection finds that approval conditions are not being met, the approval may be revoked and the licensee may be required to meet applicable base requirements immediately, or other appropriate requirements may be specified.

If a licensee anticipates that proposed changes to the facility may not meet the approval conditions, the licensee may reconfigure the facility to meet base measurement, accounting, and reporting requirements or submit a new application for site-specific approval of deviation from the base requirements. Approval must be in place prior to implementation. Submission of an application does not guarantee that an approval will be granted.

The following information is required for all applications for site-specific deviation from base requirements. Other specific information that may be required is described in the following appropriate sections.

1) Well and/or facility list, including
    - battery code and locations
    - well locations (UID)
    - licence number(s)
    - respective pool/zone designations and unique identifier for each zone
    - indication as to unit or non-unit operation, if applicable
    - royalty status (Freehold/Crown, new/old, etc.)
    - equity (ownership) issues, if any
    - latest 6 months' gas, oil/condensate, and water flow rates (or expected flow rates for new wells)
    - up-to-date measurement schematic(s) for the existing system(s) and the proposed new gas or oil source(s), including all tie-in locations, if applicable

    - facility plot plan for the existing system and the proposed new gas or oil source(s), if applicable

2) Justifications for deviation from measurement requirements (e.g., economics, minimal impact on measurement accuracy)

5.3 Chart Cycles Extended Beyond the Required Time Period

Chart cycle is the time required for a circular chart to complete one 360° revolution. An extension of the required chart cycle time may be applicable under the following scenarios:

- the gas well orifice meter chart cycle is greater than 8 days;
- the single-well oil battery orifice gas meter chart cycle is greater than 24 hours; or
- the Class 3 and 4 oil well test orifice gas meter chart cycle is greater than 8 days.

For well(s) with EFM systems that is to be mixed with paper charts on an extended chart cycle, approval from the EUB is required.

Group or sales/delivery point meters and Class 1 and 2 oil well test gas meters do not qualify for exception for chart cycle extension, and approvals for extension of the chart cycle for those meters will not normally be granted.

5.3.1 Exceptions

Orifice meter gas chart cycles may be extended without EUB site-specific approval if all the initial qualifying criteria below are met.

Initial Qualifying Criteria

1) In the case of gas well measurement, all wells in the multiwell battery are gas wells. A single-well battery does not qualify for this exception on its own; the entire group battery or gas gathering system must be considered.

2) In the case of oil well measurement, all wells in the battery are oil wells, and the well produces either to a single-well battery or to a multiwell oil group where each well has its own separation and measurement equipment.

3) All wells are subjected to the same type of measurement (all well production is separated and all components are measured, or all well production is subject to effluent measurement) and the same chart cycle.

4) All wells flowing to the battery have common ownership and either common Crown or Freehold royalty, or
    - if there is no common ownership, written notification has been given to all working interest participants, with no resulting objection received;
    - if there are no common Crown or Freehold royalties and only Freehold royalties are involved, written notification has been given to all Freehold royalty owners, with no resulting objection received. If there is a mix of Freehold and Crown royalty involved, the licensee must apply to the EUB for approval.

5) The monthly average volumetric gas flow rate for each well is $\leq 16.9\ 10^3\ m^3/d$ (including the gas equivalent of condensate in the case of gas well measurement).

6) The differential pen records at 33% or more within the chart range, and the static pressure pen should record at 20% or more within the chart range (if possible). Painted traces must not exceed 4% of the differential pressure or static pressure range. Painting occurs when there are quick up and down movements of the pen, so that there is no visible separation between the up and down traces for a period of time.

7) Temperature must be recorded at a minimum of once per week, and if that is not possible, continuous temperature measurement (temperature pen) is required.

8) The wells that are within the same battery of the extended chart cycle wells and are designed for and/or operate on on/off flows (e.g., plunger lifts, pump-off controls, intermittent timers) must be measured using EFM. In addition, an extended chart cycle with EFM is allowed.

Revocation of Exceptions

If any of the following exists or occurs, the exception is revoked:

1) Oil well/battery gas is added to a gas battery.

2) There is mixed measurement within the battery other than with EFM.

3) The oil well is not produced either to a single-well battery or to a multiwell oil group where each well has its own separation and measurement equipment.

4) The working interest participants for any well flowing to the battery have changed and a new working interest participant objects to the exception.

5) Any well within the battery has exceeded the 16.9 10^3 m^3/d monthly average actual gas production rate (including gas equivalent of condensate for gas wells).

6) Painted traces for any well exceeded 4% of the differential pressure range or the static pressure range.

7) A new well with on/off flows is added to an effluent proration battery, or one or more of the existing wells has been modified to operate on on/off flows but EFM is not used.

Base measurement requirements must be reinstated if the exception is revoked due to any of the above.

5.3.2 Applications

The following information must be submitted with an application to extend orifice meter gas chart cycles:

1) all of the information listed in Section 5.2: Site-specific Approval Applications;

2) if there are no common Crown or Freehold royalties or common ownership, documentation to address royalty and equity issues demonstrating that written notification was given to all Freehold royalty holders and working interest participants, with no resulting objection received;

3) a discussion of the impact on measurement accuracy of intermingling base chart cycles and extended chart cycles in a common battery, and how it may relate to concerns about working interest equity and/or royalty considerations;

4) a minimum of two current, consecutive, representative gas charts—Additionally, the licensee has the option to run the charts on the proposed chart cycle to gather test data for submission and then revert back to the required chart cycle after a maximum test period of 31 days. The original copies of any such charts created must be submitted with the application. The trial run must be clearly identified on the charts.

5.3.3 Considerations for Site-specific Approval

1) Differential and static pressures are stable, with essentially uninterrupted flow:
   - On/off flow as designed, including plunger lifts, pump-off controls, intermittent timers, etc., that cause painting or spiking, do not normally qualify for chart cycle extension.
   - The effects of painting are minimized. The amount of painting that is acceptable is decided case by case.
   - The differential pen should record at 33% or more within the chart range and the static pressure pen should record at 20% or more within the chart range (if possible).

2) There are minimal equity and royalty concerns.

3) Reservoir engineering concerns - The concern for well measurement accuracy declines, from a reservoir perspective, as the pool depletes. The applicant should provide its assessment/opinion, but the EUB has to decide on a case-by-case basis if the concerns are relevant.

4) All gas meters producing into the same group measurement point use the same chart cycle, so that they are subject to the same type of error.

5.4 Gas Proration Outside Southeastern Alberta Shallow Gas Zones/Area

For wells outside the boundary of and/or producing from zones other than those approved for the Southeastern Alberta Shallow Gas Zones/Area (see *IL 93-10: Revised Measurement and Accounting Procedures for Southeastern Alberta Shallow Gas Wells*), it may be acceptable to use a proration system for gas well production instead of having measurement for every well. If a proration system is implemented, all wells in the battery must be subject to the proration system.

5.4.1 Exceptions

Gas wells may be produced without individual well measurement and be connected to a proration battery without EUB site-specific approval if all the initial qualifying criteria below are met.

Initial Qualifying Criteria

1) All wells are classified as gas wells.

2) All wells flowing to the battery have common ownership and either common Crown or Freehold royalty, or

- if there is no common ownership, written notification has been given to all working interest participants, with no resulting objection received;
- if there are no common Crown or Freehold royalties and there are only Freehold royalties involved, written notification has been given to all Freehold royalty owners, with no resulting objection received. If there is a mix of Freehold and Crown royalty involved, the licensee must apply to the EUB for approval.

3) The licensee has discussed and addressed reservoir engineering issues with its own reservoir engineering staff or external knowledgeable personnel to ensure minimal reservoir engineering concerns and has documented the results for audit.

4) Total liquid production at each well in the battery is ≤ 2 m^3/d based on the monthly average flow rates recorded during the six months prior to conversion. If a group of new wells not previously on production are to be constructed as a proration battery, the qualifying flow rates must be based on production tests conducted under the anticipated operating conditions of the proration battery.

5) The maximum average daily well gas flow rate of all wells in the battery is ≤ 10.0 10^3 m^3/d (including gas equivalent volume of condensate), with the highest daily well flow rate ≤ 16.9 10^3 m^3 (including gas equivalent volume of condensate and except as allowed below). If an existing battery with measured gas well production is being converted to a proration battery, qualifying flow rates must be based on the monthly average flow rates recorded during the six consecutive months prior to conversion. If a group of new wells not previously on production are to be constructed as a proration battery, the qualifying flow rates must be based on production tests conducted under the anticipated operating conditions of the proration battery.

6) Periodic well tests are conducted under normal operating conditions to determine hourly flow rates that will be used to estimate monthly well production based on monthly well operating hours. The well tests are conducted for a minimum of 12 hours, and all gas, condensate, and water volumes are separated and measured during the test. For gas wells with minimal water production (≤0.01 m^3 water/10^3 m^3 gas) and no condensate or oil, the testing duration must be sufficient to clearly establish stabilized flow rates and single-phase testing is allowed,

7) Following the commencement of production at the proration battery, all wells are tested within the first month, then again within six months, and then annually after that. New wells added to the battery at some future date must be tested within the first month of production, then again within six months, and then annually after that.

8) For new wells tying into a gas proration battery and that will be producing more than 16.9 10^3 m^3/d but that are expected to drop below 16.9 10^3 m^3/d within six months, every well must be tested monthly for the first six months with a separator, or until the production rate has stabilized, and annually thereafter. If the gas production rate for any of the wells is more than 16.9 10^3 m^3/d after six months of production or the liquid production rate is higher than 2 m^3/d, a separator must be installed to continuously separate and measure the well production, and the measurement-by-difference rules in Section 5.5 apply in this case.

9) For coalbed methane (CBM) wells each with water production ≤ 0.01 m^3 water/10^3 m^3 gas and no condensate, if at any time more than 5.0 m^3/month of net water production is

realized at the group measurement point, the operator must investigate the source of the water production by retesting and using at least a two-phase separator at the suspected gas well(s) within 30 days and then prorate the water production accordingly.

10) The flow rates established from the well tests are used to determine estimated monthly well production from the date of the test until the date of the next test, with the exception that the test conducted during the first month of production is also used to estimate the wells' production for the producing days prior to the test. The total measured group gas and liquid production are prorated to the wells, based on each well's estimated production, to determine the actual well production.

Revocation of Exceptions

If any of the following exists or occurs, the exception is revoked:

1) An oil well is added to the battery, or one or more of the existing gas wells has been reclassified as an oil well.

2) The maximum average daily flow rate of all wells in the battery for any month exceeded 10.0 10^3 m^3/d, or the highest single well flow rate exceeded 16.9 10^3 m^3/d except as allowed above.

3) Total liquid volume exceeded 2 m^3/d during a 24-hour test period or prorated to 24 hours if the test period is not 24 hours.

4) A new well has been added to the proration battery with a daily flow rate over 16.9 10^3 m^3 except as allowed above or whose additional volume will cause the average daily well gas flow rate of all wells in the battery to exceed 10.0 10^3 m^3/d.

5) Wells within the proration battery or new wells added to the battery were not tested as required.

6) The gas proration methodology in item 10 under Initial Qualifying Criteria above was not followed.

Base measurement requirements must be reinstated if the exception is revoked due to any of the above.

5.4.2 Applications

The following information must be submitted with an application to use a proration system, instead of individual gas well measurement, to determine gas well production:

1) all of the information listed in Section 5.2: Site-specific Approval Applications;

2) a discussion of the stage of depletion for pools involved and the impact of any reduction in well measurement accuracy that may result from gas proration as it relates to reservoir engineering data needs—discussion of this matter by the licensee with its own reservoir engineering staff or knowledgeable external personnel is required and must be addressed in the application;

3) a clear explanation and flow diagram of proposed well and group measurement devices and locations, the proposed accounting and reporting procedures, and the proposed method and frequency of testing.

4) if there is no common Crown or Freehold royalties or common ownership, documentation to address royalty and equity issues demonstrating that written notification was given to all Freehold royalty holders and working interest participants, with no resulting objection received.

5.4.3 Considerations for Site-specific Approval

1) All wells must be classified as gas wells.

2) There are minimal equity, royalty, and reservoir engineering concerns.

3) All wells should have similar flow rates.

4) Economic considerations: Would implementation of a proration system reduce costs enough to significantly extend operations? Have other options been considered?

5) Total liquid production at each well in the battery should be ≤ 2 m^3/d based on the monthly average flow rates recorded during the six months prior to conversion. If a group of new wells not previously on production are to be constructed as a proration battery, the qualifying flow rates must be based on production tests conducted under the anticipated operating conditions of the proration battery.

5.5 Measurement by Difference

Measurement by difference is defined as any situation where an unmeasured volume is determined by taking the difference between two or more measured volumes. It results in the unmeasured volume absorbing all the measurement error associated with the measured volumes. In the case of a proration battery (effluent measurement, or periodic testing without continuous measurement), new gas or oil source errors may be difficult to detect because the proration testing errors in the original system can hide the new source errors. Despite these concerns, a properly designed and operated measurement system can minimize the risk and attain reasonable accuracy, provided that the measured source gas or oil rates are a small proportion of the total system delivery rates.

Gas Measurement by Difference

For gas streams, measurement by difference can include but is not limited to the following situations. (Note that all schematics below are examples only; some systems may be configured differently.)

Measured gas source(s) (other than from the designated SE Alberta Shallow Gas Zones/Area) delivering into a SE Alberta Shallow Gas proration battery (Figure 5.1):

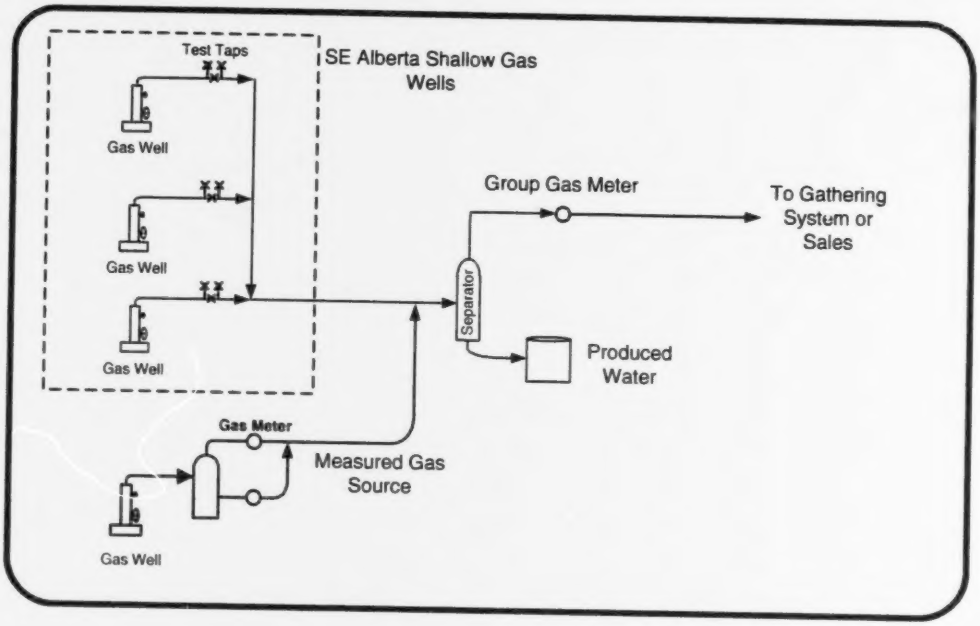
Test Taps
SE Alberta Shallow Gas Wells
Gas Well
Gas Well
Gas Well
Group Gas Meter
To Gathering System or Sales
Separator
Produced Water
Gas Meter
Measured Gas Source
Gas Well

Figure 5.1

- Measured gas source(s) delivering into a gas proration battery outside SE Alberta Shallow Gas Zones/Area (Figure 5.2):

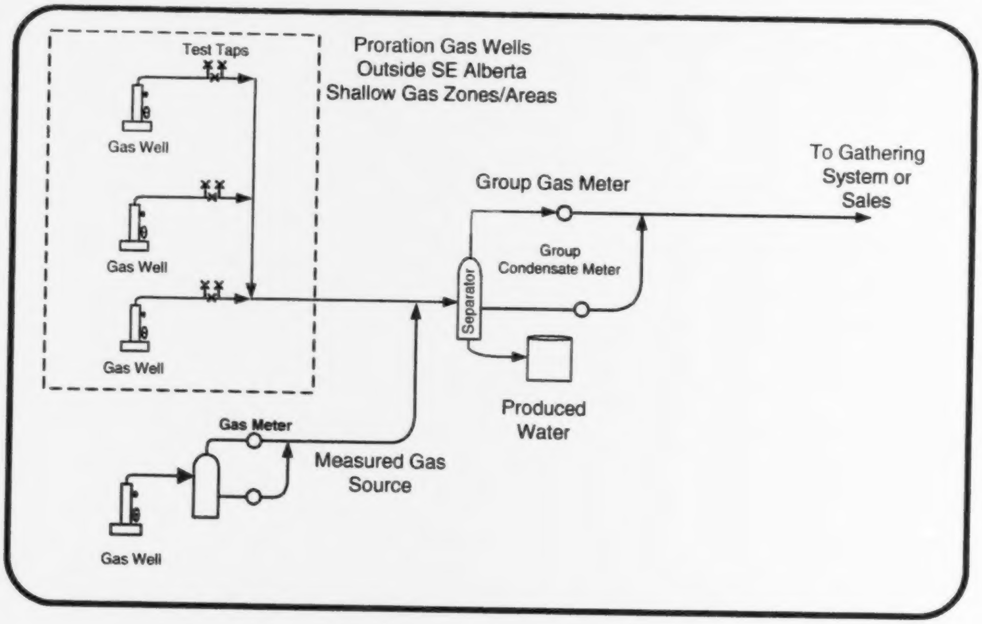
Test Taps
Proration Gas Wells Outside SE Alberta Shallow Gas Zones/Areas
Gas Well
Gas Well
Gas Well
Group Gas Meter
To Gathering System or Sales
Group Condensate Meter
Separator
Produced Water
Gas Meter
Measured Gas Source
Gas Well

Figure 5.2

- Measured gas source(s) delivering into an effluent (wet) measurement gas proration battery (Figure 5.3):

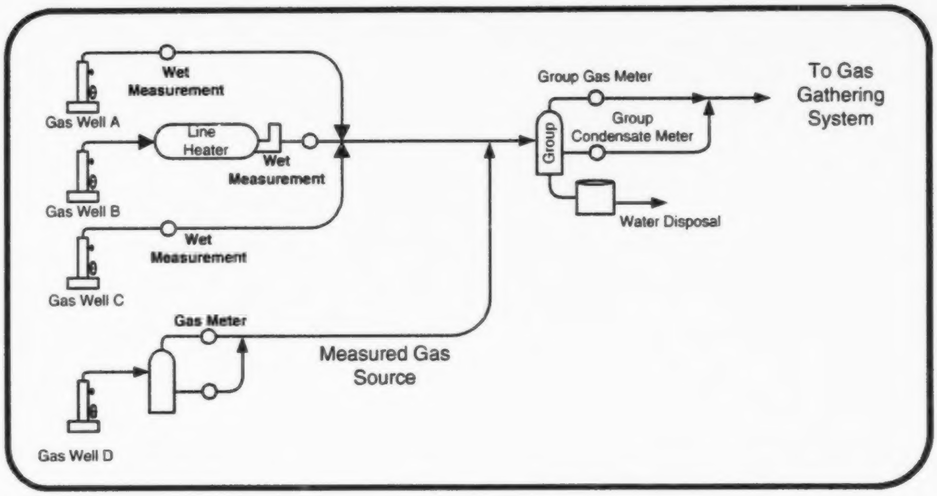
Wet Measurement
Gas Well A
Line Heater
Wet Measurement
Gas Well B
Wet Measurement
Gas Well C
Gas Meter
Measured Gas Source
Gas Well D
Group Gas Meter
Group
Group Condensate Meter
Water Disposal
To Gas Gathering System

Figure 5.3

- Measured gas source(s) delivering into an oil proration battery (Figure 5.4):

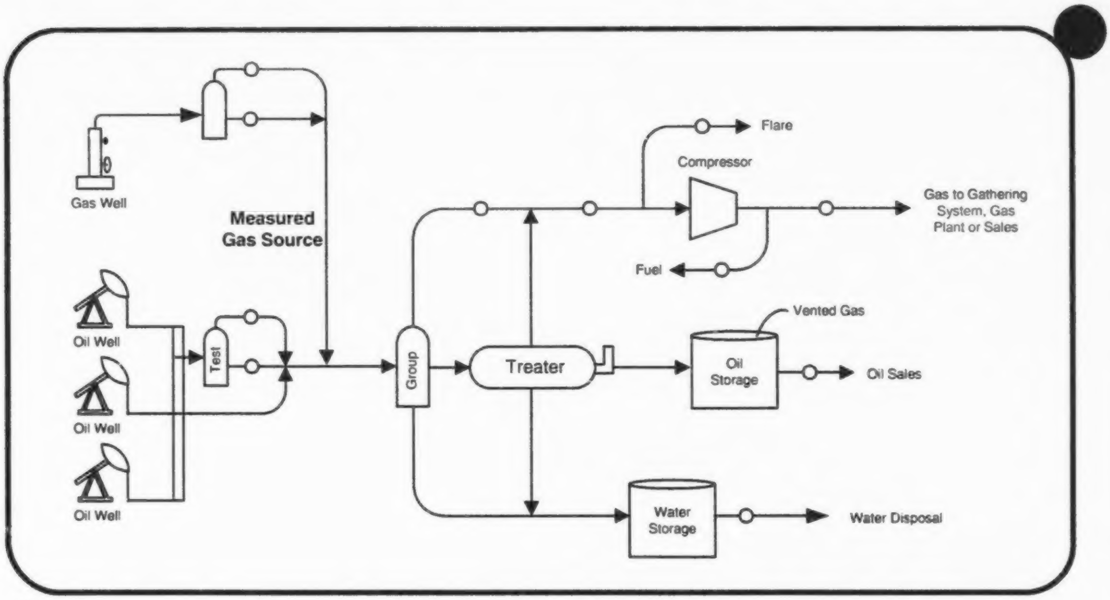
Gas Well
Measured Gas Source
Oil Well
Test
Oil Well
Oil Well
Group
Treater
Flare
Compressor
Gas to Gathering System, Gas Plant or Sales
Fuel
Vented Gas
Oil Storage
Oil Sales
Water Storage
Water Disposal

Figure 5.4

- Measured oil facility gas delivering into a gas proration battery (Figure 5.5):

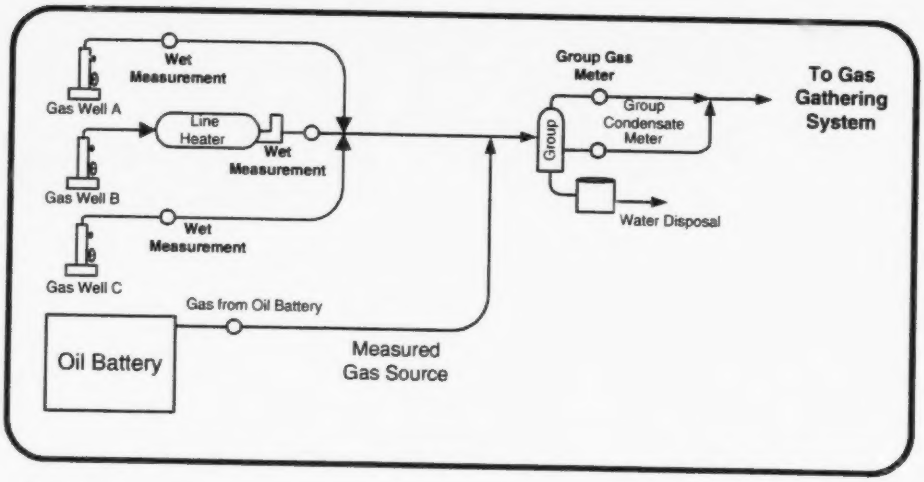
Wet Measurement
Gas Well A
Line Heater
Wet Measurement
Gas Well B
Wet Measurement
Gas Well C
Group Gas Meter
Group
Group Condensate Meter
To Gas Gathering System
Water Disposal
Gas from Oil Battery
Oil Battery
Measured Gas Source

Figure 5.5

If any measured gas source will be tied in to a gas proration battery:

1) The gas and liquids from all tied-in gas sources must be separately and continuously measured.

2) The monthly gas volume (including GEV of condensate where appropriate) received from a tied-in measured gas source (and any other receipts) must be subtracted from the total monthly battery gas volume (including GEV of condensate where appropriate) to determine the monthly battery gas production volume.

3) The table below indicates when measurement by difference may be acceptable by exception and when submission of an application may be required.

Prorated gas flow rate (excluding all measured gas source)	R* ratios		
≤0.5 10^3 m^3/d	<1.00		
>0.5 10^3 m^3/d	≤0.35	>0.35	>0.75
Application required	**No**	**Yes**	**Yes (Approval granted only in exceptional circumstances)**

* R = Ratio of volume of all tied-in measured gas volumes (including GEV of condensate where applicable) to the total battery gas disposition volume.

If any measured gas source will be tied in to an oil battery:

1) The gas and liquids from the tied-in gas source(s) must be separately and continuously measured.

2) The monthly gas volume (including GEV of condensate where appropriate) received from a tied-in measured gas source (and any other receipts) must be subtracted from the total monthly battery gas volume to determine the monthly battery gas production volume. (See Table 5.1 for options.)

3) If liquid condensate is received from a tied-in measured gas source, the monthly liquid condensate volume where appropriate must be subtracted from the total monthly oil disposition (plus/minus inventory changes and minus any other receipts) to determine the monthly battery oil production volume. (See Table 5.1 for options.)

4) The table below indicates when measurement by difference may be acceptable by exception and when submission of an application may be required.

Prorated gas flow rate (excluding all measured gas source)	**R* ratios**		
≤0.5 $10^3 m^3$/d	<1.00		
>0.5 $10^3 m^3$/d	≤0.35	>0.35	>0.80
Application required	**No**	**Yes**	**Yes (Approval granted only in exceptional circumstances)**

*R = Ratio of volume of all tied-in measured gas volumes (including GEV of condensate where applicable) to the total battery gas disposition volume.

Where a measured gas source will be tied into a single well battery, as shown in Figure 5.6, this situation does not qualify for an exception, and an application must be submitted to and approved by the EUB prior to implementation.

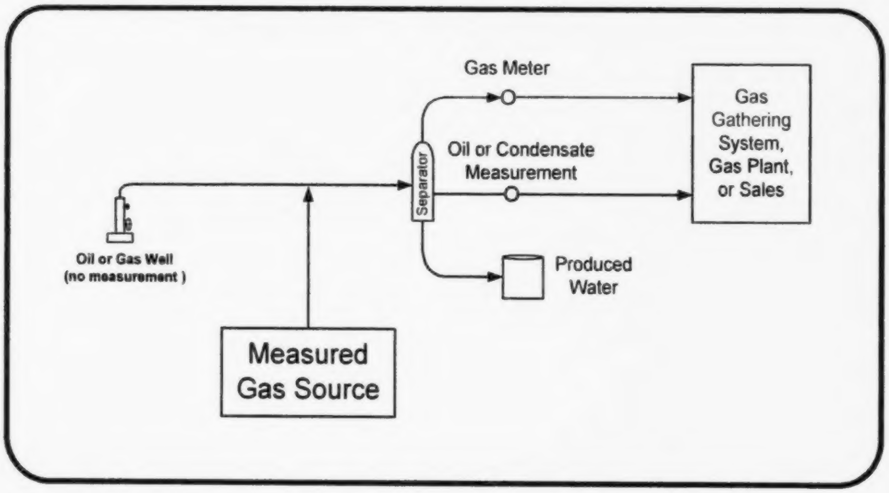
Gas Meter
Gas Gathering System, Gas Plant, or Sales
Oil or Condensate Measurement
Separator
Oil or Gas Well (no measurement)
Produced Water
Measured Gas Source

Figure 5.6

Oil Measurement by Difference

For oil streams, measurement by difference can include but is not limited to the following situations.

- Measured oil and/or oil-water emulsion from a battery delivering into an oil proration battery by truck (Figure 5.7):

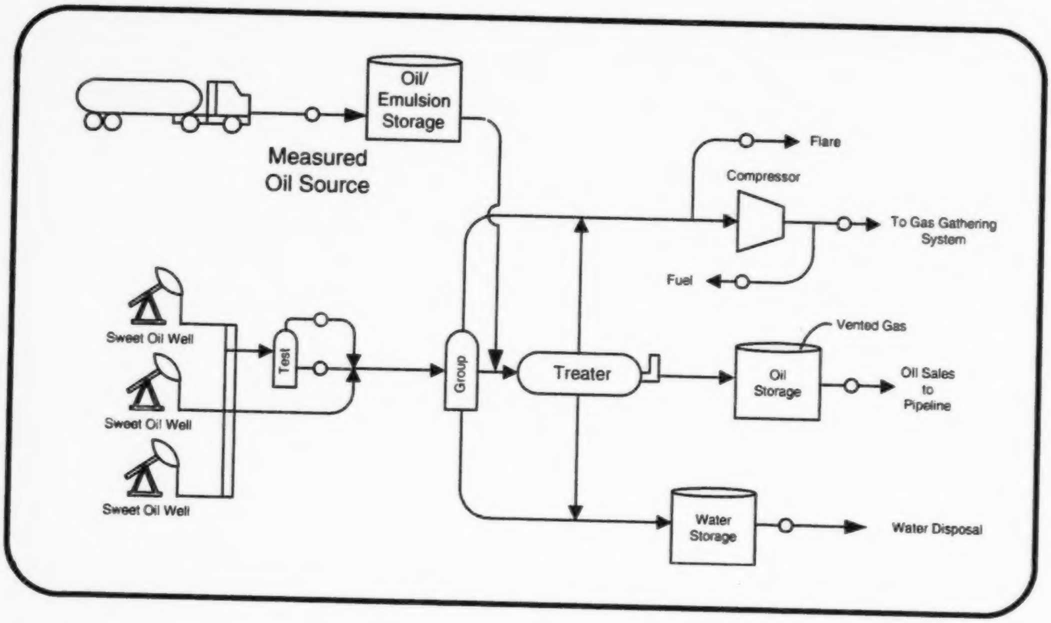
Oil/
Emulsion
Storage
Measured
Oil Source
Flare
Compressor
To Gas Gathering
System
Fuel
Vented Gas
Sweet Oil Well
Test
Group
Treater
Oil
Storage
Oil Sales
to
Pipeline
Sweet Oil Well
Sweet Oil Well
Water
Storage
Water Disposal

Figure 5.7

- Measured oil and/or oil-water emulsion (and gas if applicable) under pressure from a battery delivering into an oil proration battery by pipeline (Figure 5.8):

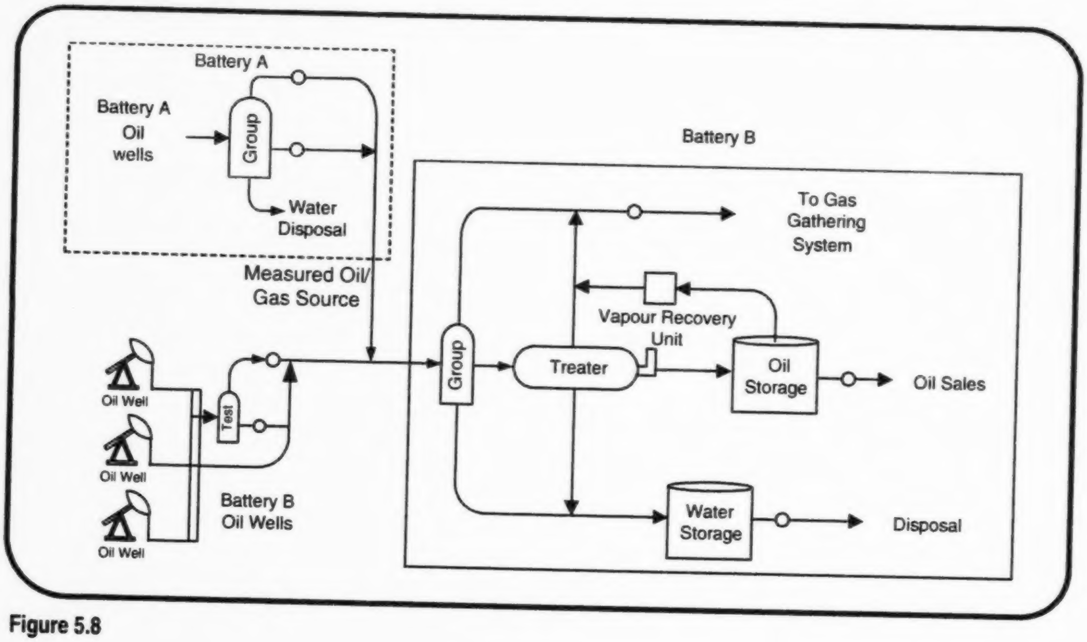
Battery A
Battery A
Oil
wells
Group
Water
Disposal
Measured Oil/
Gas Source
Battery B
To Gas
Gathering
System
Vapour Recovery
Unit
Group
Treater
Oil
Storage
Oil Sales
Oil Well
Test
Oil Well
Battery B
Oil Wells
Oil Well
Water
Storage
Disposal

Figure 5.8

If any measured oil and/or oil-water emulsion source will be delivered to a battery including trucked-in volumes:

1) Measured oil and/or oil-water emulsion delivery/receipt volumes must be determined using equipment and/or procedures that meet delivery point measurement uncertainty requirements. In the case of oil-water emulsions, the measurement uncertainty requirements apply to total volume determination only.

2) Measured oil volumes must be determined and reported at stock tank conditions.

3) The liquids received from the delivered measured oil and/or oil-water emulsion source(s) must be subtracted from the total monthly oil and water disposition volumes (plus/minus inventory changes and minus any other receipts) to determine the monthly battery oil production volume.

4) The table below indicates when measurement by difference may be acceptable by exception and when submission of an application may be required.

Measured oil delivery/receipt volume	Application required
≤1000 m^3/month or if >1000 m^3/month and ≤25% of monthly battery oil production volume	No
>1000 m^3/month and >25% of monthly battery oil production volume	Yes

5) Consideration should be given to incorporating the piped-in measured oil and/or oil-water emulsion source(s) as a satellite of the battery (if the battery is an oil proration battery) and including it in the battery's proration system. In that case, measurement by difference could be avoided.

5.5.1 Exceptions

Measurement by difference is allowed without EUB site-specific approval if all of the applicable criteria below are met.

If the measurement by difference will involve existing production, initial qualifying flow rates must be based on average daily flow rates (monthly flow rate divided by number of production days in the month) recorded during the six months prior to implementation of the measurement by difference. If new measured production is to be connected to a proration battery, the qualifying flow rates must be based on production tests conducted under the anticipated operating conditions.

Exceptions for All Measured Gas Streams

For measured gas source(s) from either gas or oil batteries tied into a gas proration battery or an oil battery:

5.5.1.1(a) Initial Qualifying Criteria

1) Volumetric criteria for measured gas tying into a proration battery

Prorated gas flow rate (excluding all measured gas source)	R*
≤0.5 10^3 m^3/d	<1.00
>0.5 10^3 m^3/d	≤0.35

*R = Ratio of volume of all tied-in measured gas (including GEV of condensate where applicable) to the total gas disposition volume from the receiving battery.

Example:

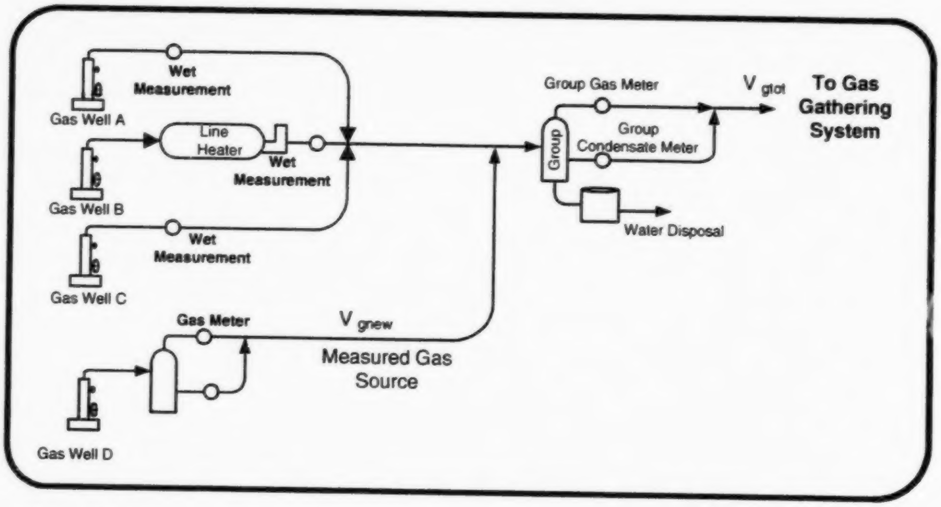
Wet Measurement
Gas Well A
Line Heater
Wet Measurement
Gas Well B
Wet Measurement
Gas Well C
Gas Meter
V gnew
Measured Gas Source
Gas Well D
Group Gas Meter
V gtot
To Gas Gathering System
Group
Group Condensate Meter
Water Disposal

Figure 5.9

For the gas battery example in Figure 5.9,

$V_{gtot} = 100\ 10^3\ m^3/d$ (total of measured gas and GEV of condensate delivered out of the battery, including volumes received from Gas Well D)

$V_{gnew} = 30\ 10^3\ m^3/d$ (total of measured gas and GEV of condensate delivered to the battery from Gas Well D)

Prorated gas flow rate $= V_{gtot} - V_{gnew} = 100 - 30 = 70\ 10^3\ m^3/d$

$R = 30/100 = 0.3$

Since the prorated flow rate is above $0.5\ 10^3 m^3/d$ and R is below 0.35 for the Well D tie-in, it is within the acceptable exception range.

2) All wells flowing to the battery have common ownership and either common Crown or Freehold royalty.
   - If there is no common ownership, written notification has been given to all working interest participants, with no resulting objection received.
   - If there is no common Crown or Freehold royalty and only Freehold royalties are involved, written notification has been given to all Freehold royalty owners, with no resulting objection received. If there is a mix of Freehold and Crown royalty involved, the licensee must apply to the EUB for approval.

3) The gas and liquid phases from the tied-in measured gas source(s) are separately and continuously measured.

4) Gas volumes received at a gas battery from the tied-in measured gas source(s) include the GEV of the measured condensate volumes if the condensate is recombined with the measured gas volumes from the new tied-in gas source.

5) If the tied-in measured gas source(s) produces condensate and it is to be connected to an oil battery, the licensee must choose from the applicable condensate delivery/reporting options in Table 5.1 below.

Table 5.1. Criteria for condensate delivery to an oil battery

Condensate rate (from measured gas sources)	≤ 2.0 m^3/day and/or ≤ 5.0% of total prorated oil production	> 2.0 m^3/day and/or > 5.0% of total prorated oil production
Option 1	Deliver condensate to the oil battery and report it all as liquid condensate if most of the condensate will not be flashed during the oil treatment process (minimal pressure drop and/or temperature increase).	Deliver condensate elsewhere; do not recombine it with the gas volumes delivered to the oil battery.
Option 2	Deliver condensate to the oil battery and report it all as a GEV if most of the condensate will be flashed during the oil treatment process (large pressure drop and/or temperature increase).	Tie in the gas well gas and condensate stream downstream of oil battery gas disposition measurement.
Option 3	Deliver condensate elsewhere; do not recombine it with the gas volumes delivered to the oil battery.	

6) If condensate from a tied-in measured gas source will be delivered to an oil battery and reported as a liquid volume, it is measured with a meter proved to stock tank conditions.

7) If condensate from a tied-in measured gas source will be delivered to an oil battery and reported as a GEV, it is measured with a meter proved to flow line conditions.

8) In the case of an oil battery or a gas proration battery, the monthly gas volume (including GEV of condensate where appropriate) received from a tied-in measured gas source (and any other receipts) is subtracted from the total monthly battery gas volume (including GEV of condensate where appropriate) to determine the monthly battery gas production volume.

9) In the case of an oil battery, the monthly liquid condensate volume (where appropriate) received from a tied-in measured gas source is subtracted from the total monthly oil disposition (plus inventory changes, shrinkage, if applicable, and minus any other receipts) to determine the monthly battery oil production volume.

10) If oil and/or oil-water emulsion from a tied-in measured gas source will be delivered to a gas proration battery, the total volume does not exceed 2 m^3/day, it is measured with a meter proved to stock tank conditions, and it is reported as a liquid.

5.5.1.1(b) Revocation of Exceptions

If any of the following exists or occurs, the exception is revoked:

1) The gas and liquid phases from the tied-in measured gas source(s) were not separately and continuously measured.

2) Measurement, accounting, and reporting of condensate in items 4 to 9 under Initial Qualifying Criteria above were not followed.
3) Measurement, accounting, and reporting of oil and/or oil-water emulsion in item 10 under Initial Qualifying Criteria above were not followed.

Base measurement requirements must be reinstated if the exception is revoked due to any of the above.

5.5.1.2 Exception for Measured Oil Streams Received by Truck

5.5.1.2(a) Initial Qualifying Criteria

1) Oil and/or oil-water emulsions may be trucked into an oil battery provided the total measured oil receipt volume is ≤1000 m^3/month, or if >1000 m^3/month, the total measured oil receipt volume is ≤25% of the monthly battery oil production volume.

2) The monthly battery oil and water production volumes are determined by subtracting the monthly measured oil and water receipt volumes from the total monthly battery oil and water disposition volumes (plus inventory change and minus any other receipts).

5.5.1.2(b) Revocation of Exceptions

If any of the following exists or occurs, the exception is revoked:

1) Trucked-in oil receipt was > 1000 m^3/month and the total measured oil receipt volume was > 25% of the monthly battery oil production volume.

2) The accounting methodology in item 2 under Initial Qualifying Criteria above was not followed.

There are three options to follow after revocation:

1) truck all oil receipts over 1000 m^3/month elsewhere, or

2) set up another treater train with separate inlet measurement, tankage, and outlet measurement to process the truck-in receipts prior to commingling with the battery production, or

3) obtain EUB special approvals to continue.

5.5.1.3 Exception for Measured Oil Streams Received by Pipeline

5.5.1.3(a) Initial Qualifying Criteria

1) Oil and/or oil-water emulsions may be pipelined into an oil battery provided that the total measured oil receipt volume is <1000 m^3/month or if >1000 m^3/month, the total measured oil receipt volume is $\leq 25\%$ of the monthly battery oil production volume.

2) All wells that belong to the oil battery and the tied-in oil source(s) have common ownership and either common Crown or Freehold royalty:
    - If there is no common ownership, written notification has been given to all working interest participants, with no resulting objections.
    - If there is no common Crown or Freehold royalty and only Freehold royalties are involved, written notification has been given to all Freehold royalty owners, with no resulting objection received. If there is a mix of Freehold and Crown royalties involved, the licensee must apply to the EUB for approval.

3) The monthly battery oil and water production volumes are determined by subtracting the monthly measured oil and water receipt volumes from the total monthly battery oil and water disposition volumes (plus inventory change and minus any other receipts).

4) If the measured gas from a measured live oil/emulsion production source is also commingled with the production at an oil battery, the exception criteria for gas measurement by difference are also met.

5.5.1.3(b) Revocation of Exceptions

If any of the following exists or occurs, the exception is revoked:

1) Piped in oil receipt was >1000 m^3 and the total measured oil receipt volume was $> 25\%$ of the monthly battery oil production volume.

2) The accounting methodology in item 3 under Initial Qualifying Criteria above was not followed.

3) Gas measurement by difference exception criteria in item 4 under Initial Qualifying Criteria above was not met.

There are three options to follow after revocation:

1) pipe all oil receipts over 1000 m^3/month elsewhere, or
2) set up another treater train with separate inlet measurement, tankage, and outlet measurement to process the pipeline receipts prior to commingling with the battery production, or
3) obtain EUB special approvals to continue.

Oil System Example:

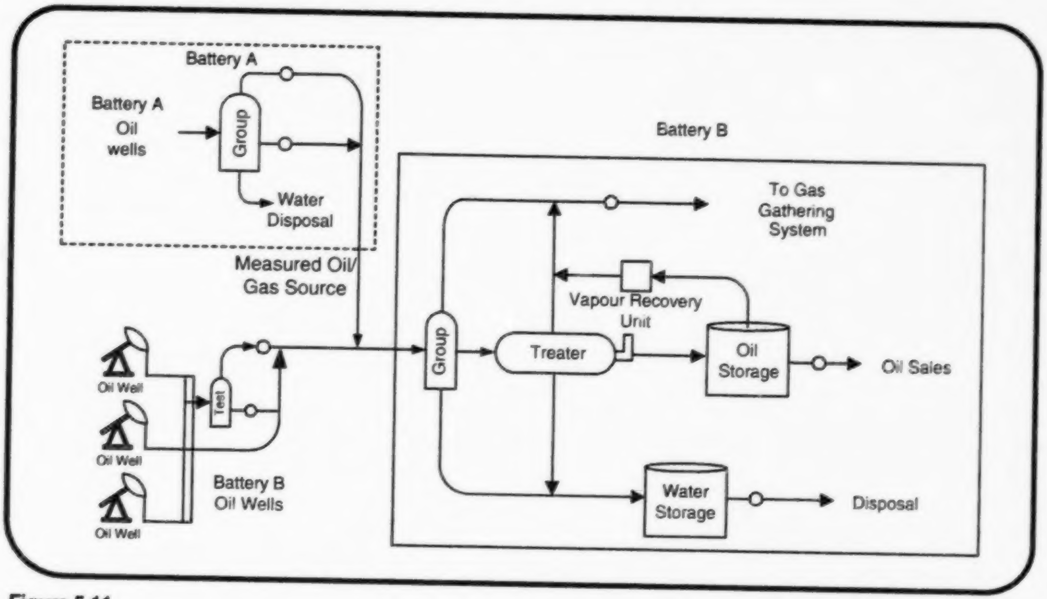
Battery A
Battery A
Oil
wells
Group
Water
Disposal
Measured Oil/
Gas Source
Battery B
To Gas
Gathering
System
Vapour Recovery
Unit
Group
Treater
Oil
Storage
Oil Sales
Oil Well
Oil Well
Oil Well
Test
Battery B
Oil Wells
Water
Storage
Disposal

Figure 5.11

Note that with the addition of Battery A production, if the measurement by difference meets all the initial qualifying criteria and the total oil delivery volume at Battery B is over 100 m^3/d, the delivery volume must be determined by a measurement device(s) and/or procedures having ±0.5% uncertainty, which might require changes in measurement equipment and/or procedures at Battery B.

For this example (Figure 5.11), given the following data,

Battery A oil production volume = 20.0 m^3/d

Battery B oil production volume = 90.0 m^3/d before tying in Battery A

Battery A gas production volume = 15.0 10^3 m^3/d

Battery B gas production volume = 20.0 10^3 m^3/d before tying in Battery A

Step 1: Calculate the monthly measured oil volume from Battery A delivered to the proration battery (Battery B) and the percentage of the prorated oil production.

Monthly measured oil production volume from Battery A = 20.0 m^3/d x 30 days = 600 m^3

Battery A oil volume as a percentage of Battery B oil production volume = 20 m^3/d / 90.0 m^3/d = 22.2%

Step 2: Calculate the R ratio for the commingled gas:

$R = 15.0/(15.0 + 20.0) = 0.43$

Since the Battery A monthly measured oil volume is below 1000 m^3/month, the oil volumetric criteria are met. However, the gas R ratio is over the 0.35 limit, so an application would be required.

5.5.2 Applications

The following information must be submitted with an application to add measured gas or oil/emulsion sources to a proration battery:

1) all of the information listed in Section 5.2: Site-specific Approval Applications;

2) a discussion of the stage of depletion for pools involved, and the impact of any reduction in well measurement accuracy that may result from measurement by difference as it relates to reservoir engineering data needs; discussion of this matter by the proponent with its own reservoir engineering staff or knowledgeable external personnel is required and must be addressed in the application;

3) if there are no common Crown or Freehold royalties or common ownership, documentation to address royalty and equity issues demonstrating that written notification was given to all Freehold royalty holders and working interest participants, with no resulting objection received.

5.5.3 Considerations for Site-specific Approval

1) There are minimal equity, royalty, and reservoir engineering concerns.

2) Economic considerations: Would implementation of a proration system reduce costs enough to significantly extend operations? Have other options been considered?

3) The gas and liquids from the tied-in measured source(s) must be separately and continuously measured.

4) If the tied-in measured gas source(s) produces condensate and it is to be connected to an oil battery, the licensee must choose from the following applicable condensate delivery/reporting options:

Table 5.2. Options for condensate delivery to an oil battery

Condensate rate (from measured gas sources)	**≤ 2.0 m^3/day and/or ≤ 5.0% of total prorated oil production**	**> 2.0 m^3/day and/or >5.0% of total prorated oil production**
Option 1	Deliver condensate to the oil battery and report it all as liquid condensate if most of the condensate will not be flashed during the oil treatment process (minimal pressure drop or temperature increase).	A laboratory analysis, or a computer software simulation based on the condensate composition must be performed to determine the amount of the condensate that will be flashed during the oil treatment process. **Flashed condensate:** report it as a GEV of condensate and include it with the gas delivery/receipt volume. **Unflashed condensate:** report it as a liquid condensate delivery/receipt volume.
Option 2	Deliver condensate to the oil battery and report it all as a GEV if most of the condensate will be flashed during oil treatment process.	Deliver condensate elsewhere and do not deliver it to the oil battery.
Option 3	Deliver the condensate elsewhere and do not deliver it to the oil battery.	

5) In the case of an oil battery or a gas proration battery, the monthly gas volume (including GEV of condensate where appropriate) received from a tied-in measured gas source (and any other receipts) must be subtracted from the total monthly battery gas volume (including GEV of condensate where appropriate) to determine the monthly battery gas production volume.

6) In the case of an oil battery, the monthly liquid condensate, or oil, and/or oil-water emulsion volume (where appropriate) received from a tied-in measured source must be subtracted from the total monthly oil and/or water disposition (plus/minus inventory changes and minus any other receipts) to determine the monthly battery oil and/or water production volume.

5.6 Surface Commingling of Multiple Gas Zones/Wells

If gas wells have been completed in multiple zones and those zones are segregated in the wellbore and produced separately to surface or if there are multiple individual gas wells on the same surface location, production from each zone or each well usually has to be measured separately prior to commingling. Where applicable, such zones or wells may be commingled at surface prior to the combined production being measured, if the conditions in the "Exceptions" section below are met or upon approval of an application. Proportionate monthly production volumes must still be determined and reported for each zone/well, in accordance with the applicable procedures described below.

The following requirements do not apply to zones that qualify for the SE Alberta Shallow Gas Proration Battery procedures if specific zones are approved (without application) for commingling in the wellbore.

Commingling of zones in the wellbore require approval from the EUB Resources Applications Group.

5.6.1 Exceptions

Surface commingling of two gas zones in a gas well or separate gas wells on the same surface location prior to measurement is allowed without EUB site-specific approval if all the initial qualifying criteria below are met.

Initial Qualifying Criteria

1) Both zones/wells have common ownership and common Crown or Freehold royalty;
   - If there is no common ownership, written notification has been given to all working interest participants, with no resulting objection received.
   - If there is no common Crown or Freehold royalty and only Freehold royalties are involved, written notification has been given to all Freehold royalty owners, with no resulting objection received. If there is a mix of Freehold and Crown royalty involved, the licensee must apply to the EUB for approval.

2) Monthly average of total liquid production from both zones is $\leq 2\ m^3/d$.

3) The combined daily flow rate of both zones/wells is $\leq 16.9\ 10^3\ m^3$, including GEV of condensate (if recombined). If the zones/wells to be commingled will involve existing production, initial qualifying flow rates are based on monthly average flow rates recorded during the six months prior to implementation of the commingling. If new zones/wells

are to be commingled, the initial qualifying flow rates are based on production tests conducted under the anticipated operating conditions.

4) Shut-in wellhead pressure of the lower pressure zone/well is ≥ 75% of the shut-in wellhead pressure of the higher-pressure zone.

5) The combined production from both zones/wells is measured continuously. Separation before measurement is required for both phases.

6) Check valves are installed on each flow line upstream of the commingling point.

7) Testing requirements:
   - Each zone/well must be tested once per month for the first six months after commingling, then annually thereafter, and/or immediately following any significant change to the producing conditions of either zone/well.
   - The tests must be conducted for at least 24 hours and must involve the separation and measurement of all gas and liquid production.
   - If condensate is recombined with the gas production of the commingled zones/wells, a sample of the condensate must be taken annually and analyzed and used to determine the factor to be used to determine the GEV.
   - The tests for both zones/wells must be done consecutively with stabilization periods.
   - Any of the three test methods described below may be used. However, methods (i) and (ii) below are preferred, because the testing is conducted under normal flowing conditions without shutting in zones/wells, so that minimal stabilization time is required.
     i) Test taps must be installed upstream of the commingling point but downstream of the check valve so that a test separator unit can be hooked up to test each zone/well individually (Figure 5.12).

Test Method (i)

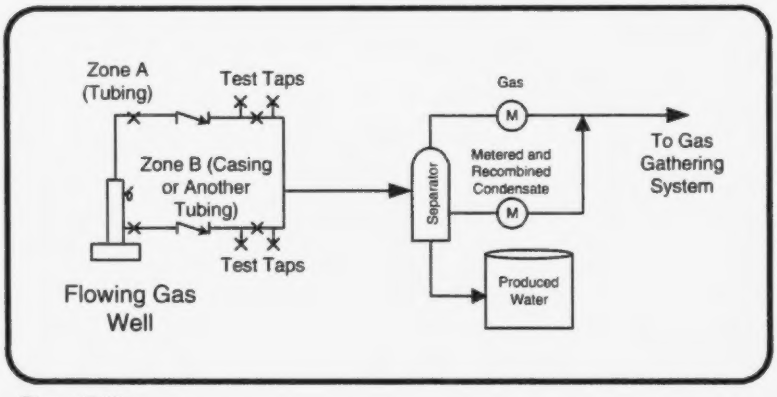

Figure 5.12

     ii) Install permanent bypasses or taps to hook up temporary bypasses downstream of the check valve so that one zone/well will be bypassing the existing separation and metering equipment while the other zone/well is tested using the existing equipment. Note that the production from the bypassed zone/well must be estimated based on the production test rates (Figure 5.13).

Test Method (ii)

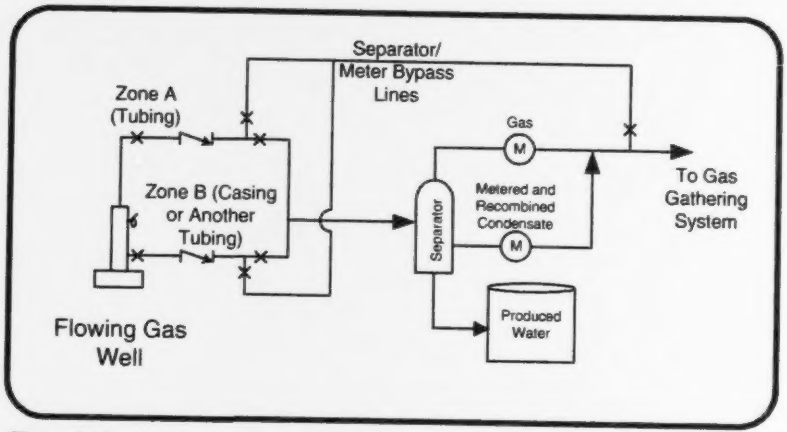
Separator/
Meter Bypass
Lines
Zone A
(Tubing)
Gas
M
To Gas
Gathering
System
Zone B (Casing
or Another
Tubing)
Separator
Metered and
Recombined
Condensate
M
Produced
Water
Flowing Gas
Well

Figure 5.13

iii) Shut in one producing zone at a time and use the existing separation and measurement equipment to test each zone/well individually after stabilization.

8) The production rates determined for each zone/well by the periodic tests must be used to estimate the monthly production for each zone/well from the date they are conducted until the next test is conducted. The monthly measured combined production must be prorated to each zone/well based on the estimates, and those prorated volumes must be reported as the monthly production for each zone/well.

Revocation of Exceptions

If any of the following exists or occurs, the exception is revoked:

1) The combined production from both zones/wells was not measured continuously or there was no separation before measurement.

2) Check valves were not installed on each flow line upstream of the commingling point.

3) Testing requirements in item 7 under Initial Qualifying Criteria above were not followed.

4) The gas proration methodology in item 8 under Initial Qualifying Criteria above was not followed.

Base measurement requirements must be reinstated if the exception is revoked due to any of the above.

5.6.2 Applications

The following information must be submitted with an application to commingle production at surface prior to measurement from multiple zones in a gas well or multiple wells on the same surface location:

1) all of the information listed in Section 5.2: Site-specific Approval Applications;

2) shut-in and proposed operating pressures at the wellhead for all zones/wells;

3) operating pressure for the gathering system at the well site measurement point;

4) proposed testing procedures to determine the individual zone/well production rates; and

5) proposed accounting procedures for prorating total volumes to the individual zones/wells.

6) If there are no common Crown or Freehold royalties or common ownership, documentation to address royalty and equity issues demonstrating that written notification was given to all Freehold royalty holders and working interest participants, with no resulting objection received.

5.6.3 Considerations for Site-specific Approval

1) Generally, there is ≤ 2 m^3/day of total liquid production from all zones/wells.

2) All zones/wells must be classified as gas zones/wells.

3) There are minimal equity, royalty, and reservoir engineering concerns.

4) The combined production of all zones/wells must be continuously measured. If there are gas and liquid components, they must be separately measured.

5) Check valves must be in place on the flow line upstream of the commingling point.

6) Testing requirements:
   - Each zone/well must be tested once per month for the first six months after commingling, then annually after that, and/or immediately following any significant change to the producing conditions of either zone/well.
   - The tests must be conducted for at least 24 hours in duration and must involve the separation and measurement of all gas and liquid production.
   - If condensate is recombined with the gas production of the commingled zones/wells, a sample of the condensate must be taken annually and analyzed and used to determine the factor that will be used to determine the GEV.
   - The tests for all zones/wells must be done consecutively, with stabilization periods.
   - Any of the three test methods described in the exceptions section above may be used, with the consideration that more than two zones/wells may be involved. However, methods (i) and (ii) are preferred, because the testing is conducted under normal flowing conditions without shutting in zones/wells, so that minimal stabilization time is required. The EUB may specify test procedures if specific circumstances warrant them.

7) The production rates determined for each zone/well by the periodic tests must be used to estimate the monthly production for each zone/well from the date they are conducted until the next test is conducted. The monthly measured combined production must be prorated to each zone/well based on the estimates, and those prorated volumes must be reported as the monthly production for each zone/well.

6 Conventional Oil Measurement

This section presents the base requirements and exceptions for conventional crude oil and emulsion measurements from wells and batteries in the upstream oil and gas industry that are used in determining volumes for reporting to the Petroleum Registry. The requirements for crude oil/emulsion volumes transported by truck are detailed in *IL 90-6* and *IL 92-8*, which will be replaced by the Trucked Liquid Measurement section (under development).

Conventional crude oil has the following characteristics:

- it is a mixture mainly of pentanes and heavier hydrocarbons that may be contaminated with sulphur compounds,
- it is recovered or is recoverable at a well from an underground reservoir,
- it is liquid at the conditions under which its volume is measured or estimated.
- it must have a density of less than 920 kg/m^3 at standard conditions.

6.1 General Requirements

Crude oil may be found in association with water in an emulsion. In such cases, the total liquid volume must be measured, and the relative volumes of oil and water in the emulsion must be determined by obtaining and analyzing a representative sample of the emulsion, by using a product analyzer, or by other means if applicable. Applications for which estimation of water content is appropriate (e.g., inventory) are covered in more detail later in this section.

A licensee must measure produced crude oil/emulsion volumes by tank gauging, weigh scale, or meter, unless otherwise stated in this directive. The EUB will consider an oil measurement system to be in compliance if the base requirements detailed below are met. The EUB may stipulate additional or alternative requirements for any specific situation based on a site-specific assessment and will inform licensees in writing of any additional or alternative requirements respecting their facilities.

6.2 General Measurement, Accounting, and Reporting Requirements for Various Battery Types

6.2.1 General Accounting Formula

Production = Total disposition + Closing inventory – Opening inventory – Total receipts

6.2.2 Oil Batteries

6.2.2.1 General

All wells in the battery must be classified as oil wells.

Liquid production from an oil battery must be measured as an oil, water, or oil/water emulsion volume. This measurement may be performed at the battery site, a truck delivery/receipt point, or a pipeline delivery point. The meter factor obtained from meter proving must be applied to the meter volumes until another prove is conducted.

All wells in a multiwell oil battery must be subject to the same type of measurement (measured or prorated). If there is a mixture of measured and prorated wells within the same battery, the exception criteria in Section 5.5 must be met or a EUB site-specific approval must be obtained.

Production from gas batteries or other oil/bitumen batteries may not be connected to an oil proration battery upstream of the oil proration battery group measurement point(s) unless specific criteria are met or an EUB approval is obtained (see Section 5.5).

6.2.2.2 Single-well Battery

Oil/emulsion must be separated from gas and measured.

6.2.2.3 Multiwell Group Battery

Each well must have its own separation and measurement equipment, similar to a single-well battery.

All equipment for the wells in the battery must share a common surface location.

6.2.2.4 Proration Battery

All well production is commingled prior to the total battery oil/emulsion being separated from the gas and measured. Individual monthly well oil production is estimated based on periodic well tests and corrected to the actual monthly volume through the use of a proration factor.

Double proration, whereby the proration oil battery disposition volume(s) is prorated to group measurement points and then further prorated to the wells, is not allowed unless an approval to do so has been obtained from the EUB.

6.2.3 Gas Batteries Producing Oil

6.2.3.1 General

All wells in the battery must be classified as gas wells.

Oil production, receipt, disposition, and inventory volumes must be reported as liquid oil. Oil volumes must not be converted to a gas equivalent volume (GEV) and must not be added to the gas volumes. If oil is recombined with the gas and delivered to a gas plant (through a gas gathering system), the oil volume as determined at the battery must be reported as delivered to the gas plant. The gas plant must report the oil disposition as appropriate.

6.2.3.2 Single-well Battery

Oil/emulsion must be separated from gas and measured.

6.2.3.3 Multiwell Group Battery

Each well must have its own separation and measurement equipment, similar to a single-well battery, and its gas production must be connected by pipeline to a common location for further processing.

6.3 Base Requirements for Oil Measurement

6.3.1 System Design and Installation of Measurement Devices

The system design and installation of oil/emulsion measurement devices must be in accordance with the following.

6.3.1.1 Meters

The meter and its associated peripheral equipment and piping must be designed and installed according to applicable industry-accepted standards or the manufacturer's recommendation. Temperature measurement must be in accordance with Table 6.1.

Table 6.1. Required frequency for oil/emulsion temperature measurement

Criteria or events	Minimum frequency
Delivery point (if a meter is used) EFM devices (optional for production proration testing)	Continuous
Delivery point batch volumes into a pipeline or receipt at a battery/facility using tank gauging	One reading per load

Note that the temperature-measuring element must be installed in the flow stream and be representative of the oil/emulsion stream temperature—that is, the licensee cannot use the surface temperature of the piping or install the element where there is normally no flow. A meter equipped with a temperature compensation device is considered to have continuous temperature measurement.

6.3.1.2 Tank Gauging

The licensee must ensure that the gauge tape, the strapping table, or the calculation used to convert gauge level to a liquid volume is appropriate for the tank being gauged.

With the exception of inventory determination, the licensee must ensure that the tank level is not changing when the gauge readings are taken. (This often requires isolating the tank before gauging.)

6.3.1.2a Tank Sizing Requirements for Testing or Delivery Point Measurement

The relative accuracy of the volume determination using tank gauging depends on several factors and includes both random and bias errors. Such factors include the accuracy of the gauge tape, the strapping table used, the condition of the gauge point on the tank, the difference in temperature of the of the tank volume before and after the transaction, and the level of operator training.

The primary function is to convert a level measurement to a volume measurement, and the precision that can be achieved when tank gauging is of concern. Since the precision that can be achieved by manual tank gauging is relatively consistent, the main way to determine accurate tank volumes is by ensuring that the level change corresponding to the transaction or test volume is large compared to the overall tank height. This can be achieved by selecting a tank design such that the ratio of volume per height of fluid is low.

The following formulas may be used to determine these values:

$V \geq a \times d^2$ or $d \leq (V/a)^{1/2}$

where

V = test fluid volume or delivery point batch volume in m^3
d = tank diameter in metres
a = accuracy coefficient

The accuracy coefficient = 0.39 for all test fluid volumes
= 0.39 for delivery point batch volumes ≤ 100 m^3/d
= 0.92 for delivery point batch volumes > 100 m^3/d

6.3.1.2b Flow Line Delivery Point Measurement Gauging

When tank gauging is used to determine an oil/emulsion volume, the gauging procedures must be conducted in accordance with the following:

- The licensee must ensure that the gauge/strapping table used to convert the gauge level to a liquid volume is specific for the tank being gauged.
- With the exception of inventory determination, the licensee must ensure that the tank level is not changing or is stabilized when the gauge readings are taken. This often requires isolating or shutting in the tank before gauging.
- All gauge tapes and electronic level devices must have a minimum resolution of 3 mm.

Gauge boards are not acceptable for delivery point measurement.

Manual Tank Gauging

For tanks with a nominal capacity greater than 160 m^3, two consecutive readings within 10 mm of each other are required; the two readings are then averaged.

For tanks with a nominal capacity of 160 m^3 or less, one reading is acceptable.

Automatic Tank Gauging

One reading of the instrument is acceptable.

6.3.1.2c Inventory Tank Gauging

For monthly inventory measurement gauging, one reading of the gauge tape, gauge board, or automatic tank gauge is acceptable. The required resolution for reporting is to the nearest 75 mm.

Gauge board markings must be no farther apart than 150 mm.

6.3.1.2d Test Tank Gauging

For gauge measurement on test tanks, one reading of the gauge tape, gauge board, or automatic tank gauge is acceptable.

Gauge board markings must be no farther apart than 25 mm, and where safe work conditions allow, gauge board readings should be taken at eye level. The required resolution for reporting is to the nearest 10 mm.

6.3.1.3 Electronic Flow Measurement

Electronic oil measurement systems must be designed and installed according to the requirements in Section 6.8. Any EFM system designed and installed in accordance with API MPMS, Chapter 21.2, will meet the audit trail and reporting requirements, but a performance evaluation is still required in accordance with Section 6.8.

6.3.2 Volumetric Calculations

Crude oil volume measurements must be determined to two decimal places and rounded to one decimal place for monthly reporting. Where there is more than one volume determination within the month at a reporting point, the volumes determined to two decimal places must be totalled prior to the total being rounded to one decimal place for reporting purposes.

6.3.2.1 Temperature Correction Requirements

Temperature measurement used for volume correction must be representative of the actual fluid temperature. Total monthly oil volumes for wells (production) and batteries (production, receipts, dispositions, and delivery point) must be reported in cubic metres at a standard temperature of 15°C and rounded to the nearest tenth of a cubic metre (0.1 m^3). Battery or facility opening and closing inventory volumes for monthly reporting must be rounded to the nearest 0.1 m^3 but do not require correction to 15°C. The temperature correction (**C**orrection for the effect of **T**emperature on **L**iquids [CTL]) factor must be determined in accordance with API MPMS, Chapter 11.1.

In a proration battery, if well test oil volumes are determined by a meter, temperature compensation must be applied using one of the following methods:

- Apply a composite meter factor that incorporates a CTL factor. To arrive at a composite meter factor, divide the temperature corrected prover volume by the indicated meter volume for each prover run.
- Apply a CTL factor in real time using an electronic flow measurement system.
- Apply a CTL factor to the total test volume based on a single temperature measurement taken during the test.

See Table 6.1 for temperature measurement frequency requirement.

6.3.2.2 Pressure Correction Requirements

Correction to a 0.0 kPa gauge (atmospheric pressure) must be performed for continuous flow crude oil pipeline measurement where custody transfer measurement is performed. The pressure correction (**C**orrection for the effect of **P**ressure on **L**iquids [CPL]) factor must be determined in accordance with API MPMS, Chapter 11.

All other crude oil/emulsion measurements, such as delivery point and test oil, do not require CPL correction.

6.3.2.3 Shrinkage Factor

At the test separator, the oil is normally at its bubble point (equilibrium vapour pressure) condition. When the oil is discharged to a stock tank at atmospheric condition, the light components in the oil evaporate, causing a reduction in liquid volume. Therefore, a shrinkage factor must be applied to correct the measured liquid volume from metering condition to stock tank condition. Degassing a prover prior to taking the volume reading for each run effectively incorporates the shrinkage factor into the meter factor and requires no further correction for shrinkage. However, sufficient time must be allowed for the degassing to take place.

Shrinkage factors can also be determined by laboratory or software simulation methods and applied to the test oil volume, eliminating the need for degassing during proving. Shrinkage factors may be determined at either a well or battery level, depending on variation. The frequency of shrinkage factor determination should reflect changes in reservoir or operating conditions. Further details on calculation and use of shrinkage factors are in API MPMS, Chapter 20.1.

6.3.2.4 General Volume Calculations

The oil volume calculations must adhere to the following:

1) Total indicated volume for the transaction period (daily, weekly, monthly) is measured and recorded. This applies to measurement by meter, by weight scales, or by tank gauging.

2) The volumetric meter factor for the flow meter is applied to the total indicated volume.

3) The percentage of water in the gross volume is determined by measuring the percentage of sediments and water (% S&W) of a representative sample or by continuous on-line measurement. The result is a quantified volume of oil and of water. It is also possible to use a computer algorithm to determine the oil and water volumes in the emulsion based on the measured density of the emulsion and the known density of the oil and water components of the emulsion. The oil and water base density must be based on an analysis of the actual oil and water production being measured and must be corrected for the temperature at which the emulsion density is measured.

4) A shrinkage factor is applied to the oil volume in order to determine the volume at stock tank conditions (ambient pressure). As noted in Section 6.3.2.3 above, some applications may already have the shrinkage factor incorporated into the meter factor.

5) For delivery point measurement, a CTL is applied to the oil volume to determine the volume at a standard temperature of 15°C. Some applications may already have the CTL incorporated into the meter factor. Applying CTL is optional for a test oil volume, as long as the selected practice is consistent for the area.

The general formula for determining oil volumes is as follows:

$$\text{Oil volume} = (\text{End reading} - \text{Start reading}) \times \text{MF} \times (1 - \%\text{S\&W}) \times \text{CTL} \times \text{CPL} \times \text{SF}$$

where

MF = meter factor
%S&W = percentage of sediments and water
SF = shrinkage factor due to apparent loss of volume due to entrained gas
CTL = volume correction factor for the effects of temperature on liquid
CPL = volume correction factor for the effects of pressure on liquid

For test oil measurement, composite meter factors may include CTL, CPL, or shrinkage factor or some combination of the three, depending on the application.

A composite meter factor including CPL is acceptable where pressure is stable between proves.

Correction for shrinkage is not required when oil has been reduced to atmospheric pressure prior to measurement.

6.3.3 Production Data Verification and Audit Trail

The field data, records, and any calculations or estimations, including EFM, relating to EUB-required production data submitted to the Petroleum Registry of Alberta must be kept for inspection upon request. The reported data verification and audit trails must be in accordance with the following:

1) Test records: any records and documentation produced in the production proration testing of wells that affect measured volumes

2) Proving records: any records and documentation produced in the proving of meters and calibration of the prover and all peripheral devices (if the prover and peripheral devices are owned and operated by the licensee)

3) S&W records: any records and documentation produced in the determination of relative oil/water percentages that affect volumes

4) Delivery and receipt records: any records and documentation produced in the determination of delivery or receipt volumes

5) Estimation records: any records and documentation related to the estimation of reported volumes, including estimation methodology, record of event, and approvals

6) Tank gauging records: any records and documentation produced in the determination of reported volumes

7) Volume loss records: any records and documentation for volumes lost due to incidents such as theft, spills, and fires

8) EFM: any records and documentation (electronic, magnetic, or paper form) produced in the determination of measured volumes in accordance with the EFM requirements in Section 6.8

6.4 Field Operations

6.4.1 Production Hours

Physical well shut-ins and emergency shutdowns (ESDs) are considered downtime. Other occurrences resulting in downtime may be wax or hydrates plugging lines and some other failures. If the well has no oil production but still has gas production, it is considered to be on production. The operations personnel have to make a determination based on the operating environment in other situations when the wells are not physically shut in but may not have oil and gas production.

Oil wells operating on an on/off cycle basis, such as intermittent timers, pump-off controls, and plunger lifts, that are "operating normally and as designed on repeated cycles" and where part of the operation involves shutdown of pump equipment and/or periodic shut-in of the wells (as part of the repeated cycle) are considered on production even when the wells are not pumping or flowing.

6.4.2 Fluid Sampling Requirements for S&W Determination (and Density)

S&W determination procedure including the frequency of sampling must be representative of the entire volume transaction as well as the subsequent S&W sample analysis. There are two methods to obtain this measurement: sampling or on-line analysis using a suitable instrument (water-cut analyzer or product analyzer). Sampling can be categorized by two methods: spot or grab sampling or continuous proportional sampling. It is important that the sample location be carefully selected such that the flowing stream is adequately mixed. This can be achieved by

- installing in-line mixers,

- selecting a sampling point that offers the most practical location for collecting a sample that is mixed, such as after valves, elbows, and reducers,
- selecting a sampling point that is downstream of a metering point because of the piping elements associated with a meter run, or
- collecting samples from a number of different locations, analyzing them, and making a selection based on the location that provides the most consistent and reasonable analysis.

Grab or spot sampling may be used if the water cut is below 10% for proration oil testing. Otherwise continuous proportional sampling or the use of a product analyzer is required.

Water-cut analyzers operate on a number of different principles and often are suited for specific applications. Analyzers must be installed and maintained in accordance with the manufacturer's recommendations.

For a single-well oil battery or a multiwell group oil battery delivering emulsion off-site, the volumes will be determined by the receiving facilities.

For single-well oil batteries with two-phase or three-phase separators delivering produced oil/emulsions by pipeline to another battery, the sample must be taken at or near the oil/emulsion meter using a continuous proportional sampler. Or a product analyzer is used on-site. This is a measurement-by-difference situation (see Section 5.5).

For an oil battery with emulsion tanks, the oil and water inventory volumes in the emulsion tanks may be determined by:

- taking a spot (grab) sample anywhere between the wellhead or separator and the tank and applying the %S&W to the tank inventory,
- using water-indicating paste on the gauge tape to determine the water/oil interface in the tank inventory,
- using a representative thief sample taken from the tank,
- taking the average %S&W of the total battery production and applying that to the tank inventory,
- using the average %S&W of the trucked out volumes, or
- deeming the tank inventory to be entirely oil and making changes/amendments based on delivery volumes.

6.4.3 S&W Analysis

The licensee must select the most appropriate method for determining the %S&W. There are three methods generally considered acceptable by the EUB based on the %S&W:

1) the centrifuge or Karl Fischer method (combined with separate method for sediment determination) for water cuts between 0 and 10%,

2) the graduated cylinder method of a larger sample for water cuts between 10 and 80% and centrifuging the oil emulsion portion, and

3) the graduated cylinder method of a larger sample for water cuts between 80 and 100% and not centrifuging the oil emulsion portion.

Recommended procedures for these three methods are shown in Appendix 4. Any alternative methods must be supported by testing that shows representative results are achieved and these alternative procedures must be made available to the EUB upon request.

6.4.4 Proration Well Testing

Proration testing requirements for conventional crude oil wells are detailed in Table 6.2.

Table 6.2. Proration testing requirements for conventional crude oil wells

Class[a]					
No.	Name	Oil rate (m^3/d)	Minimum test frequency	Minimum time between tests[b] (days)	Minimum test duration[c] (hours)
1	High	>30	3 per month[d]	5	12
2	Medium	>6 but ≤30	2 per month[e]	10	22
3	Low	>2 but ≤6	1 per month	15	22
4	Stripper	≤2	1 every quarter	45	22

[a] Classification for each well must be determined at least semi-annually based on the average daily oil rate since the last assessment. If a well experiences operational changes that cause a change in the oil rate that could affect the classification, the operator must immediately change the classification. The average daily oil rate must be based on producing days (not calendar days).

[b] Minimum separation time between tests if minimum number of tests are conducted—the time between tests may be reduced if more than the minimum number of tests are conducted.

[c] Licensees should conduct longer duration tests for wells exhibiting erratic rates to obtain more representative test data.

[d] For Class 1 wells, the minimum test frequency is based on the assumption that the well is on production for the entire calendar month. The test frequency may be reduced to two per month if the well is shut in for at least 10 days within the month and to one per month if the well is shut in for at least 20 days within the month.

[e] For Class 2 wells, the minimum test frequency is based on the assumption that the well is on production for the entire calendar month. The test frequency may be reduced to one per month if the well is shut in for at least 15 days within the month.

6.4.4.1 Well Test Considerations

If there is a change in operating conditions during a test, such as due to a power failure or a change in choke setting, the test must be rejected and a new test must be conducted.

If there is insufficient or lost test data, such as due to meter failure, the test must be rejected and a new test must be conducted.

If there is a significant change in oil, gas, or water for a test, the validity of the test should be questioned and a retest should be considered.

Sufficient purge time must be allowed to ensure that liquids from the previous test are displaced by the new test well liquids.

The pressure difference between the test separator and the group line must not exceed 200 kPa.

A well test may be stopped early for operational reasons and still be considered valid. Reasons for the short test must be documented and made available to the EUB upon request.

6.4.4.2 Common Flow Lines

For common flow lines, a well test must be conducted, with all other wells on the common flow line shut in following adequate purge time.

Combined (cascade) testing is allowed for common flow-lined wells, provided that the conditions in Section 6.7 are met. However, the combined test must be conducted first, and then the low gas producing well must be shut in to test the high gas producing well, allowing sufficient purging and stabilization time.

6.4.4.3 Field Header and Common Flow Line Purging

If a field header is located in the same building as the test separator, the test separator must be purged by allowing at least two liquid dumps to occur prior to starting the well test.

If a field header is not located in the same building as the test separator, sufficient purge time must be allowed to ensure that liquids from the previous test are replaced by the new test well liquids.

If two or more wells are tied into a common flow line, only one well must be produced during the well test, and the other well(s) must be shut in. Similar to a field header situation, sufficient purge time must be allowed to ensure that liquids from the previous production condition are replaced by the new test well liquids.

Sufficient purge time must be calculated as follows:

Purge time = Test line volume ÷ New test well liquid flow rate

Example: Calculate the minimum purge time required for the following test line:

Test line dimensions = 1500 m length, 88.9 mm OD pipe, 3.2 mm wall thickness

Previous well test flow rates = 5.5 m^3 oil/d, 12.0 m^3 water/d

Step 1

$d = (88.9 - 3.2 \times 2) \div 1000 = 0.0825$ m

$$\begin{aligned}\text{Test line volume} &= (3.142 \times d^2 \times \text{length}) \div 4 \\ &= (3.142 \times (0.0825)^2 \times 1500) \div 4 \\ &= 8.02\ \text{m}^3\end{aligned}$$

Step 2

Purge time required = Test line volume (m^3) ÷ Well flow rate (m^3/h)

$$\begin{aligned}\text{Well total liquid flow rate} &= (5.5\ \text{m}^3 + 12.0\ \text{m}^3) \div 24\ \text{h} \\ &= 0.729\ \text{m}^3/\text{h}\end{aligned}$$

$$\begin{aligned}\text{Purge time required} &= 8.02\ \text{m}^3 \div 0.729\ \text{m}^3/\text{h} \\ &= 11.0\ \text{h}\end{aligned}$$

Therefore, the minimum purge time required is 11.0 hours.

6.5 Oil Proration Battery Accounting and Reporting Requirements

Prorated production is an accounting system or procedure in which the total battery production is allocated to wells based on individual well tests. Production from multiple oil wells may be commingled before separation and continuous single-phase measurement of the components (see Figure 6.1). Individual well production must be tested periodically to determine the production rates that can be used to estimate the well's monthly production volume. The estimated monthly well production volume is corrected using a proration factor. In summary, the following must be performed (see Section 6.5.1 for details):

- test production volumes of gas (in 10^3m^3) and oil and water (in m^3) rounded to two decimal places;
- record test duration hours to two decimal places with the nearest quarter hour as the minimum resolution;
- determine the hour production rate for each product from the well;
- determine the estimated well production by multiplying the hour rate by the monthly hours of production; and
- determine the actual (prorated) production volume by multiplying the estimated well production by the proration factor (the total actual battery production volume divided by the total estimated battery production volume).

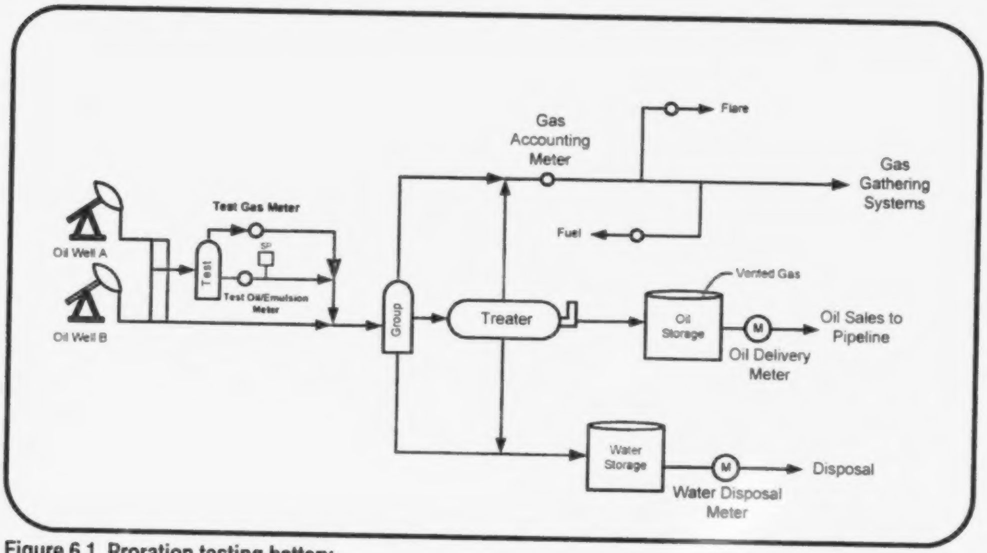
Flare
Gas Accounting Meter
Gas Gathering Systems
Test Gas Meter
Fuel
Oil Well A
SP
Test
Test Oil/Emulsion Meter
Vented Gas
Group
Treater
Oil Storage
M
Oil Sales to Pipeline
Oil Delivery Meter
Oil Well B
Water Storage
M
Disposal
Water Disposal Meter

Figure 6.1. Proration testing battery

The minimum test frequency and duration requirements (see Table 6.2) apply to all conventional oil wells under primary production and waterflood operations included in proration batteries.

Monitoring the performance of miscible floods and other enhanced oil recovery schemes usually requires testing criteria other than rate alone; therefore, testing requirements for miscible flood schemes are set out in each scheme approval.

Licensees must monitor the classification for wells producing to a battery and meet the required testing frequency and duration for each well (see Table 6.2). Some latitude to the classifications is allowed. For example, considering all wells producing to a battery or satellite as a lower rate class would be considered appropriate if a small proportion of the wells only marginally exceeded the upper limit of that classification.

Many low-rate and stripper wells exhibit erratic production rates due to high water-oil ratios or gas-oil ratios, and oversized production lines and test separators can make accurate measurement difficult. Longer test duration can improve test accuracy for many of these wells. To allow licensees the opportunity to conduct longer duration tests, class 3 and 4 wells are allowed to use up to an eight-day cycle chart drive for measurement of test gas production volumes.

The use of automatic well testing equipment and procedures with EFM provides licensees the opportunity to conduct tests of shorter durations than specified in Table 6.2. The automation computer can monitor the test and use statistical calculation methods to ensure that a representative rate is obtained prior to terminating the test. This practice is acceptable when

- the accumulated oil test volume is polled at a frequency of at least once per hour,
- the criteria for stabilization ensures that the uncertainty for the monthly well oil volume does not exceed half of the maximum uncertainty of monthly volume stipulated in Section 1, and
- the computer program is properly documented and available to the EUB upon request.

The test-to-test method, whereby data from a test are used to estimate production until the next test is conducted, must be used to estimate the production volume from each oil well based on the test rate and the total production hours. This production estimation method and the proration methodology are outlined below. A licensee may use its own worksheet format, provided that the required data are retained and available to the EUB upon request.

6.5.1 Proration Estimated Volume Calculation

Calculate the estimated production of each well from the test data using the sample worksheet on the next page.

1) Calculate the test rate/hour for crude oil, gas, and water:

   Rate per hour = Test production volume (including GIS volumes for gas) ÷ Test duration (hr)

   Enter the test rate/hour rounded to four decimal places.

2) Calculate the hours of production for each test rate during the reporting month. Include only the hours of prorated production:

   a) hours of production from the first day of the month to the start of the first test for the month—data from the last test conducted during the previous month will be used to estimate production until the first test for the month is conducted, and

   b) hours of production from the start of each test conducted during the month up to the start of the next test, or the end of the month, whichever is applicable.

   Enter the hours produced rounded to the nearest hour.

3) Calculate the estimated production of oil, gas, and water for the production hours applicable to each test rate:

   Estimated production = Test rate/hour x Hours produced

   Enter the estimated production of oil, gas, and water rounded to one decimal place.

4) Calculate the totals for each well:

   Add the hours produced that are applicable to each test rate and enter the total.

Add the estimated production of oil, gas, and water, and enter the totals.

Note that if a GOR is used to estimate the well gas production in accordance with Section 4.3.5:

Estimated well gas production = Estimated well oil production x GOR

UID	AB WI 100060100101W400						Hourly test rate				Estimated production		
	Test date		Test oil	Test gas	Test water	Test duration[c]	Oil	Gas	Water	Prod	Oil	Gas	Water
Vessel	dd	mm	m^3	$10^3 m^3$	m^3	hours	m^3/hr	$10^3 m^3/hr$	m^3/hr	hours	m^3	$10^3 m^3$	m^3
Prior mo.	25	6	9.05	1.35	3.53	24.00	0.3771	0.0563	0.1471	96	36.2	5.4	14.1
	5	7	8.85	1.28	3.26	24.00	0.3688	0.0533	0.1358	168	62.0	9.0	22.8
	12	7	9.40	1.51	2.98	24.00	0.3917	0.0629	0.1242	216	84.6	13.6	26.8
	21	7	9.15	1.67	3.65	24.00	0.3813	0.0696	0.1521	264	100.7	18.4	40.2
									Totals	744	283.5	46.4	103.9

UID	AB WI 100080100101W400						Hourly test rate				Estimated production		
	Test date		Test oil	Test gas	Test water	Test duration[c]	Oil	Gas	Water	Prod	Oil	Gas	Water
Vessel	dd	mm	m^3	$10^3 m^3$	m^3	hours	m^3/hr	$10^3 m^3/hr$	m^3/hr	hours	m^3	$10^3 m^3$	m^3
Prior mo.	28	6	5.05	0.95	4.15	24.00	0.2104	0.0396	0.1729	48	10.1	1.9	8.3
	[a]3	7	5.85	1.25	4.50	48.00	0.2406	0.0490	0.1792	336	80.8	16.5	60.2
	[a]4	7	5.70	1.10	4.10								
	17	7	6.01	1.15	5.00	25.50	0.2357	0.0451	0.1961	168	39.6	7.6	32.9
	24	7	5.40	0.99	4.10	22.75	0.2374	0.0435	0.1802	192	45.6	8.4	34.6
									Totals	744	176.1	34.4	136.0

UID	AB WI 100160100101W400						Hourly test rate				Estimated production		
	Test date		Test oil	Test gas	Test water	Test duration[c]	Oil	Gas	Water	Prod	Oil	Gas	Water
Vessel	dd	mm	m^3	$10^3 m^3$	m^3	hours	m^3/hr	$10^3 m^3/hr$	m^3/hr	hours	m^3	$10^3 m^3$	m^3
Prior mo.	1[b]	7	1.80	1.10	2.20	24.00	0.0750	0.0458	0.0917	24	1.8	1.1	2.2
	2[b]	7	4.00	2.00	5.00	24.00	0.1667	0.0833	0.2083	120	20.0	10.0	25.0
	7	7	3.95	1.95	4.95	23.00	0.1717	0.0848	0.2152	288	49.4	24.4	62.0
	19	7	4.25	2.05	5.05	26.00	0.1635	0.0788	0.1942	216	35.3	17.0	41.9
	28	7	5.65	2.00	5.50	27.75	0.2036	0.0721	0.1982	96	19.5	6.9	19.0
									Totals	744	126.0	59.4	150.1

Note that test gas volumes must include gas-in-solution (GIS) volumes (see Section 4.3.5).

[a] Tests on July 3 and 4 were comparable and consecutive (i.e., there were no operational changes). Therefore, the results are combined and used as one 48-hour test.

[b] Tests on July 1 and 2 were not comparable due to operational changes (e.g., choke/pump speed). Therefore, they are used as separate 24-hour tests.

[c] Test duration must be reported to the nearest quarter hour as the minimum resolution (record hours to two decimal places, e.g., 2 hr and 45 min are entered as 2.75 hr).

6.5.2 Calculate Proration Factors and Monthly Production

1) Calculate the total estimated battery production for oil, gas, and water:

Total estimated battery production = Sum of all the wells' total estimated production

2) Calculate the total actual battery production and proration factors for oil, gas, and water:

For oil and water,

Total actual battery production = Total monthly disposition + Closing inventory – Opening inventory – Total receipts

For gas,

Total actual battery production = Total monthly disposition (sales, fuel, flare, vent) – Total receipts

Proration factor = Total actual battery production ÷ Total estimated battery production

The proration factors for oil, gas, and water must be rounded to five decimal places.

Note that if a GOR is used to estimate the total battery gas production volume in accordance with Section 4.3.5:

Estimated battery gas production = Actual battery oil production x GOR

Estimated battery gas production = Actual battery gas production

Gas proration factor = 1.00000

3) Calculate each well's monthly prorated production volumes for oil, gas, and water:

Monthly prorated oil volume = Well estimated oil production x Oil proration factor

Monthly prorated gas volume = Well estimated gas production x Gas proration factor

Monthly prorated water volume = Well estimated water production x Water proration factor

4) Check that total well production equals total actual battery production for oil, gas, and water. If the volumes are not equal due to rounding, minor adjustments to the monthly volumes may be required.

Sum of prorated well production = Total actual battery production

6.6 Condensate Receipts at an Oil Battery

If condensate that could be flashed into the gas phase is received at an oil battery, the licensee must choose from the applicable condensate reporting options in Table 5.2.

If condensate received from an external source will be reported as a GEV, that volume must be subtracted from the total monthly battery gas disposition volume to determine the monthly battery gas production volume.

If condensate that could be flashed off into the gas phase is received at an oil battery, the licensee must report it as below:

- If condensate received into the battery is ≤2.0 m^3/day and/or ≤5% of the battery oil production, the condensate can be reported as all liquid condensate or as a GEV.
- If condensate received into the battery is >2.0 m^3/day and/or >5% of the battery oil production, the licensee must report flashed condensate as a GEV receipt volume and unflashed condensate as a liquid condensate receipt.

Note that this may also be applicable to other light hydrocarbons delivered into an oil battery.

6.7 Combined (Cascade) Testing

When a prorated oil well has such low gas production that it cannot properly operate test equipment, a licensee may test two wells simultaneously—combined (cascade) test—through the same test separator. In such cases, the following procedure must be followed:

1) Establish oil, gas, and water production volumes for a high gas producing well by testing it individually through the test separator.
2) Conduct a test for both the high gas producing well and a low gas producing well together through the same test separator immediately after testing the high gas producing well, allowing time for stabilization. (The testing sequence may be reversed with the testing of the combined wells first.)
3) The operating condition of both wells must not be changed. If it is, a new set of tests is required.
4) Total test oil, gas, and water volumes determined for the combined (cascade) test minus the test oil, gas, and water volumes for the high gas producing well will be the test volumes for the low gas producing well (see example below).
5) Both wells should have similar S&W percentages. If any of the calculated oil, gas, or water volumes for the low gas producing well are negative, the tests are not valid and both tests must be repeated.

The use of combined (cascade) testing does not require special approval from the EUB.

Example

Well A = High gas producing
Well B = Low gas producing

Test Results

Well	Test date	Oil (m^3)	Gas (10^3 m^3)	Water (m^3)
Well A+B	July 4	80.0	20.0	20.0
Well A	July 5	50.0	19.0	12.0
Well B = (Well A+B - Well A)	**July 4**	**30.0**	**1.0**	**8.0**

6.8 Electronic Flow Measurement for Oil Systems

An EFM system is defined as any flow measurement and related system that collects data and performs flow calculations electronically. If it is part of a Distributed Control System (DCS), Supervisory Control and Data Acquisition system (SCADA), or Programmable Logic Controller system (PLC), only the EFM portion has to meet the requirements in this section.

The following systems are not defined as an EFM:

- any meter with an electronic totalizer or pulse counter that does not perform flow calculations (with or without built-in temperature compensation)
- a remote terminal unit (RTU) that transmits any data other than flow data and does not calculate flow

6.8.1 Performance Evaluation

If an EFM is used to calculate clean oil volumes, the licensee must be able to verify that it is performing within the EUB target limits defined in this section.

A performance evaluation test must be completed within **two weeks** after the EFM is put into service and **immediately** after any change to the computer program or algorithms that affects the flow calculation; documentation must be kept and provided to the EUB upon request. For existing EFM systems, the licensee should conduct its own performance evaluations periodically to ensure that they are performing adequately. A performance evaluation must be conducted and submitted for EUB audit on request. The EUB considers either one of the following methods acceptable for performance evaluation:

a) Conduct a performance evaluation test on the system by inputting known values of flow parameters into the EFM to verify the volume calculation and other parameters. The test cases included in this section are for oil/emulsion meters, each with different flow conditions.

   Test cases 1 to 5 are for oil density correction from flowing temperature to 15°C. When a hydrometer is used to measure density, a hydrometer correction is required to compensate for the glass expansion. Density correction to 15°C is only required for blending shrinkage calculations, mass-based measurement, and the CTL and CPL calculations.

   Test cases 6 to 10 are for volume correction using CPL and CTL factors to correct to 101.325 kPa and 15°C. Other manufacturers' recommended methodologies may also be used to evaluate the EFM performance, provided that the volumes obtained from a performance evaluation test agree to within ±0.1% of those recorded on the sample test cases.

b) Evaluate the EFM calculation accuracy with a flow calculation checking program that performs within the target limits for all the factors and parameters listed in the test cases below. A snapshot of the instantaneous flow parameters and factors, flow rates, and configuration information is to be taken from the EFM and input into the checking program. If the instantaneous EFM flow parameters, factors, and flow rates are not updated simultaneously, multiple snapshots may have to be taken to provide a representative evaluation.

The densities (test cases 1 to 5) or volumes (test cases 6 to 10) obtained from a performance evaluation test must agree to within ±0.1% of those recorded on the sample test cases. If the

±0.1% limit is exceeded, the EFM must be subjected to a detailed review of the calculation algorithm to resolve the deviation problem.

Test Cases for Verification of Oil Flow Calculation Programs

Density and volume corrections in the table below are based on API MPMS, Chapter 11.1 (May 2004).

The hydrometer correction is based on API MPMS, Chapter 9.3 (November 2002).

Density correction to 15°C

	Inputs		Outputs	
	Oil density @ flowing temperature (kg/m^3)	Observed temperature (°C)	Oil density corrected to 15°C (kg/m^3) (with hydrometer correction)	Oil density corrected to 15°C (kg/m^3)(without hydrometer correction)
Test Case 1	875.5	120	942.9	945
Test Case 2	693	11.4	689.9	689.8
Test Case 3	644	84.45	704.7	705.7
Test Case 4	625.5	53.05	660.8	661.4
Test Case 5	779	25	786.7	786.8

Volume correction using pressure and temperature correction factors (CPL and CTL)

	Inputs				Outputs			
	Metered volume (m^3)	Oil density @ 15°C (kg/m^3)	Flowing temperature (°C)	Flowing pressure (kPa[gauge])	CTL to 15 °C-	CPL to 101.325 kPa	CTL corrected volume (m^3)	CTL & CPL corrected volume (m^3)
Test Case 6	60	903.5	40.5	700	0.98071	1.0005	58.8	58.9
Test Case 7	15	779	3.9	400	1.0112	1.00034	15.2	15.2
Test Case 8	100	1008	89	3700	0.95472	1.00255	95.5	95.7
Test Case 9	250	875.5	5	200	1.00799	1.00013	252	252
Test Case 10	150	640	75	1000	0.90802	1.00365	136.2	136.7

EFM Reports

When any parameter that affects the flow calculation is changed, such as meter factor, fluid densities, or transmitter range, a signoff procedure or an event log must be set up to ensure that the change is made in the EFM system. All data and reports must be retained for a minimum of 12 months.

The required information on each report must be stored using electronic/magnetic (not necessarily on the EFM) or printed media. They may exist individually on different formats or reports, and must be generated upon request by the EUB, as follows:

- **Daily** for daily report required data
- **Monthly** for monthly report required data
- Event and alarm logs at regular intervals before information is overwritten
- Meter reports on request for audit

The Daily Report

The daily report must include

- meter identification

- daily accumulated flow with indicating flags for estimated flow made by the system or manual inputs and alarms that have occurred for overranging of end devices
- hours on production or hours of flow (specify)
- flow data audit trail—include at least one of the following:
  - instantaneous values for flow rate, operating pressure (if applicable), and temperature taken at the same time each day,
  - average daily values for volumes, operating pressure (if applicable), and temperature, or
  - hourly accumulated flow rate and average hourly values for operating pressure (if applicable) and temperature.

Existing EFM systems that predate *Guide 34* approvals, do not have any of the above audit trail capabilities, and cannot develop the capability due to system limitations should be evaluated for upgrading when new production is tied into the facilities. The EUB may request upgrades if audit/inspection results indicate that they are warranted.

The Monthly Report

The monthly report is for the entire system, providing data for each measurement point. It is to contain the following at each measurement point as applicable:

- monthly cumulative flow
- flags indicating any change made to flow volumes
- total hours on production or hours of flow (specify)

The Meter Report

The meter report details the configuration of each meter and flow calculation information. These values are used as part of the "audit trail" to confirm that the flow calculation is functioning correctly. The meter report must include the following as applicable and be produced upon request:

1) Instantaneous flow data:
   - instantaneous flow rate
   - instantaneous operating pressure
   - instantaneous flowing temperature
   - CTL
   - CPL

2) Current configuration information:
   - meter identification
   - date and time
   - atmospheric pressure
   - pressure base
   - temperature base
   - calibrated operating pressure range
   - calibrated temperature range
   - meter factor and/or k factor
   - shrinkage factor

The Event Log

The event log is used to note and record exceptions and changes to the flow parameter, configuration, programming, and database affecting flow calculations, such as

- transmitter range changes
- algorithm changes
- meter factor or k-factor changes
- other manual inputs

The Alarm Log

The alarm log includes any alarms that may have an effect on the measurement accuracy of the system. The time of each alarm condition and the time each alarm is cleared must be recorded. Alarms that must be reported include

- master terminal unit failures
- remote terminal unit failures
- communication failures
- low-power warning
- high/low volumetric flow rate
- overranging of end devices

Appendix 1 Sections Under Development

Gas Proration Battery

Gas and Liquid Sampling and Analysis

Cross Border Measurement

Heavy Oil and Crude Bitumen Production Measurement

Trucked Liquid Volume Measurement

Acid Gas and Sulphur Measurement

Condensate and High Vapour Pressure Liquid Measurement

Liquid Measurement

Water Production Measurement

Water Injection and Disposal Measurement

Gas Lift Systems

Downhole Gas/Liquid Separation and Injection Systems

Waste Processing and Disposal Measurement

Appendix 2 EUB Documents Replaced Fully or Partially by *Directive 017: Measurement Requirements for Upstream Oil and Gas Operations*

Total Replacement (rescinded on date *Directive 017* becomes effective):

Informational Letter (IL) 86-03: Automated Measurement Systems
IL 87-1: Compressibility Factors Used in Gas Volume Calculations and Physical Property Data for Natural Gases
IL 89-16: Guidelines for Automated Measurement System Applications, ERCB Guide G-34 Comparative Chart Data
IL 91-9: Exemption from Gas Measurement Crude Oil/Bitumen Wells
Interim Directive (ID) 90-2: Gas Meter Calibration
ID 91-3: Clarification (May 2001): Heavy Oil/Oil Sands Operations
ID 94-1: Measurement of Oil, Gas & Water Production

Partial Replacement:

For sections in ILs and IDs that are no longer effective, see the documents on the EUB Web site www.eub.gov.ab.ca:
IL 90-6: Measurement Guidelines - Trucked Oil Production
IL 92-8: Crude Oil Pipeline Truck Terminal Measurement Guidelines
IL 94-7: Coriolis Force Flowmeters
ID 91-3: Heavy Oil/Oil Sands Operations

Directive 007: Production Accounting Handbook
Guide 34: Guidelines for Automated Measurement System Applications—Note that for those systems approved under *Guide 34*, the guide is still in effect.
Directive 046: Production Audit Handbook
Directive 060: Upstream Petroleum Industry Flaring Guide
Directive 063: Oilfield Waste Management Facility Inspection Manual
Directive 064: Facility Inspection Manual

Note that this directive conflicts with Appendices 6 and 12 of the September 2002 draft *Guide 7: Production Accounting Handbook*. However, when the draft is finalized, the conflicts will be removed or changed.

Appendix 3 Glossary

The definitions that follow are for the purposes of this directive only.

Absolute Density of Gas - The gas's mass per unit volume at a specific pressure and temperature. Absolute densities are generally expressed in kg/m³ at 101.325 kPa(a) and 15°C.

Absolute Density of Liquid - The liquid's mass per unit volume at a specific pressure and temperature. Absolute density of a liquid is generally expressed as kg/m³ at 101.325 kPa(a) and 15°C.

Accuracy - The ability of a measuring instrument to indicate values closely approximating the true value of the quantity measured.

Acid Gas - Gas separated in the treating of solution or nonassociated gas that contains hydrogen sulphide (H_2S), totally reduced sulphur compounds, and/or carbon dioxide (CO_2).

Allowable - Used in connection with a well, means the amount of oil or gas a well is permitted to produce, in accordance with an order of the EUB Board for this purpose, after application of any applicable penalty factor.

Bias - Any influence on a result that produces an incorrect approximation of the true value of the variable being measured. Bias is the result of a predictable systematic error.

Battery - A system or arrangement of tanks or other surface equipment receiving the effluents of one or more wells prior to delivery to market or other disposition, and may include equipment or devices for separating of the effluents into oil, gas, or water and for measurement.

Block - An area or part of a pool consisting of drilling spacing units grouped for the purpose of administering a common, aggregate production allowable.

Butane - In addition to its normal scientific meaning, a mixture mainly of butanes that ordinarily may contain some propane or pentanes plus.

Calibration - Procedures or operations that establish the accuracy of the values indicated by a measuring device as compared to the values indicated by a calibration instrument that has accuracy traceable to a suitable measuring standard. Adjustments are made, if required, to the measuring device to make it comparable to the calibration instrument. May also refer to the procedure used to determine the volume of a prover.

Central Processing Facility - A battery system or arrangement of tanks or other surface equipment receiving the effluent of one or more wells or a satellite prior to delivery to market or other disposition; may include equipment or devices for separating the effluents into crude bitumen, gas, or water for the injection and distribution of air, steam, gas, hydrocarbon, or other materials, for water treatment and recycling, and for measurement but does not include a processing plant.

Common Crown or Freehold Royalty - When all the wells in a battery are produced under Crown mineral leases and the Crown receives the same royalty rate for each well, or when under leases granted by one Freehold mineral holder, the Freehold mineral holder receives the same royalty rate for each well. If there is more than one Freehold mineral holder for the wells in a battery, the total royalty rate for each well is the same.

Common Ownership - All wells in a battery belong to the same working interest participant, or if there is more than one working interest participant, each working interest participant has the same percentage interest in each well in the battery.

Compressor Station - An installation of service equipment that receives natural gas from a well, battery, or gathering system prior to delivery to market or other disposition and is intended to maintain or increase the flowing pressure of the gas; includes any equipment for measurement.

Condensate - A mixture mainly of pentanes and heavier hydrocarbons that may be contaminated with sulphur compounds, that is recovered or is recoverable at a well from an underground reservoir and that may be gaseous in its virgin reservoir state but is liquid at the conditions under which its volume is measured or estimated.

Confidence Level - The degree of confidence that may be placed on an estimated range of uncertainty.

Crude Bitumen - A naturally occurring viscous mixture, mainly of hydrocarbons heavier than pentane, that may contain sulphur compounds and that in its naturally occurring viscous state will not flow to a well.

Crude Oil - A mixture mainly of pentanes and heavier hydrocarbons that may be contaminated with sulphur compounds, that is recovered or is recoverable at a well from an underground reservoir, and that is liquid at the conditions under which its volume is measured or estimated; includes all other hydrocarbon mixtures so recovered or recoverable except raw gas, condensate, or crude bitumen.

Custom Treating Plant - A system or arrangement of tanks and other surface equipment receiving oil/water emulsion exclusively by truck for separation prior to delivery to market or other disposition.

Dehydrator - An apparatus or a process designed and used to remove water from raw gas.

Delivery Point - The point at which the delivery of oil or gas production from a battery or facility is measured. The volumes determined at this point are typically used in royalty calculations, such as sales, cross border, gas plant to facility, or gas plant to gas plant meters.

Delivery Point Measurement - The type of measurement required at a delivery point.

Electronic Flow Measurement (EFM) - Any flow measurement and related system that collects data and performs flow calculations electronically.

Emulsion - A combination of two immiscible liquids, or liquids that do not mix together under normal conditions.

Enhanced Recovery - The increased recovery from a pool achieved by artificial means or by the application of energy extrinsic to the pool; such artificial means or application includes pressuring, cycling, pressure maintenance, or injection to the pool of a substance or form of energy but does not include the injection in a well of a substance or form of energy for the sole purpose of

- aiding in the lifting of fluids in the well, or
- stimulating the reservoir at or near the well by mechanical, chemical, thermal, or explosive means.

Error - The difference between true and observed values.

Error (random) - An error that varies in an unpredictable manner when a large number of measurements of the same variable are made under effectively identical conditions.

Error (spurious) - A gross error in procedure (for example, human errors or machine malfunctions).

Error (systematic) - An error that in the course of a number of measurements made under the same conditions on material having the same true value of a variable either remains constant in absolute value and sign or varies in a predictable manner. Systematic errors result in a bias.

Ethane - In addition to its normal scientific meaning, a mixture mainly of ethane that ordinarily may contain some methane or propane.

Exception - Circumstances under which if specific criteria are met or approval is granted, measurement devices or procedures are allowed to deviate within specified limits from base measurement requirements.

Facility - Any building, structure, installation, equipment, or appurtenance over which the EUB has jurisdiction and that is connected to or associated with the recovery, development, production, handling, processing, treatment, or disposal of hydrocarbon-based resources or any associated substances or wastes; includes, without limitation, a battery, processing plant, gas plant, oilfield waste management facility, central processing facility as defined in the *Oil Sands Conservation Regulation* (AR 76/88), compressor, dehydrator, separator, treater, custom treating plant, produced water-injection plant, produced water disposal plant, miscible flood injection plant, satellite, or any combination of any of these, but does not include a well, pipeline as defined in the *Pipeline Act*, mine site or processing plant as defined in the *Oil Sands Conservation Regulation* (AR 76/88), or mine site or coal processing plant as defined in the *Coal Conservation Act*.

Gas - Raw gas or marketable gas or any constituent of raw gas, condensate, crude bitumen, or crude oil that is recovered in processing and that is gaseous at the conditions under which its volume is measured or estimated.

Gas Battery - A system or arrangement of surface equipment receiving the effluent from one or more gas wells that provides separation, measurement, dehydration, dew point control, compression, or other gas handling functions prior to the delivery to market or other disposition; does not include gas processing equipment.

Gas Gathering System – A reporting entity that may consist of pipelines used to move gas production from oil batteries, gas batteries, and/or other facilities to another facility (usually a gas plant); may include compressors, line heaters, dehydrators, measurement, and other equipment.

Gas-in-Solution (GIS) - Gas dissolved in an oil volume under pressure.

Gas Plant - A system or arrangement of equipment used for the extraction of hydrogen sulphide, helium, ethane, natural gas liquids, or other substances from raw gas. Does not include a wellhead separator, treater, dehydrator, or production facility that recovers less than 2 m^3/day of hydrocarbon liquids without using a liquid extraction process (e.g., refrigeration, desiccant). In addition, does not include an arrangement of equipment that removes small amounts of sulphur (less than 0.1 tonne/day) through the use of non-regenerative scavenging chemicals that generate no hydrogen sulphide or sulphur dioxide.

Gas Well - A well that produces primarily gas from a pool or portion of a pool wherein the hydrocarbon system is gaseous or exhibits a dew point on reduction of pressure, or any well so designated by the EUB.

Good Production Practice (GPP) - Production of crude oil or raw gas at a rate

- not governed by a base allowable, but
- limited to what can be produced without adversely and significantly affecting conservation, the prevention of waste, or the opportunity of each owner in the pool to obtain his share of production.

Heavy Oil - Crude oil having a density of 920 kg/m^3 or greater at 15°C.

Hydrocarbon Liquid - A fluid in the liquid state that may consist of one or more of the following: oil, bitumen, condensate, ethane, propane, butane, pentane plus, or other heavier hydrocarbon compounds.

Initial Qualifying Criteria - Criteria that must be met to qualify for an exception. If the initial qualifying criteria have been met and the exception is implemented, it may remain in place indefinitely, as long as the wells do not meet any of the revocation clauses and there are no physical additions to the battery or facility (e.g., new wells or zones). If additions or changes are made to the battery or facility, the initial qualifying criteria must be met for all the wells or zones added to the battery or facility for the exception to remain in place.

Injection/Disposal Facility - A system or arrangement of surface equipment associated with the injection or disposal of any substance through one or more wells.

Innage Gauge - The depth of liquid in a tank as measured from the surface of the liquid to the tank bottom or to a fixed datum plate.

In Situ Operation

- a scheme or operation ordinarily involving the use of well production operations for the recovery of crude bitumen from oil sands, or
- a scheme or operation designated by the EUB as an in situ operation, but does not include a mining operation.

Licensee - The holder of a licence according to the records of the EUB; includes a trustee or receiver-manager of property of a licensee.

Liquid/Gas Ratio (LGR) - A ratio calculated by dividing the total water and/or condensate test volumes by the measured test gas volume.

Master Meter - A meter of known accuracy that is connected in series with another meter for the purpose of checking the accuracy of that meter and providing a meter factor.

Maximum Uncertainty of Monthly Volume - Relates to the limits applicable to equipment and/or procedures used to determine the total monthly volume.

Mean - A value in the middle of two extremes (the two values farthest apart in a group of values).

Measured Gas Source(s) - Single-phase measured gas source(s) downstream of separation and removal of liquids; also includes the gas equivalent volume (GEV) of measured condensate if the condensate is recombined after measurement with the gas downstream of the separator.

Measured Oil - Oil measured using equipment and/or procedures meeting delivery point measurement requirements and/or uncertainty limits. For emulsion, the delivery point measurement uncertainty limits apply to the total volume determination only.

Measurement - A procedure for determining a value for a physical variable.

Measurement by Difference - Any situation where an unmeasured volume is determined by taking the difference between two or more measured volumes.

Measuring Standard - A device used in calibration or proving that has a known value traceable to national reference standards maintained by the National Research Council in Ottawa, Ontario.

Meter Factor - A dimensionless number used to correct indicated meter volumes to adjusted volumes if the two volumes differ due to operational conditions (e.g., gas entrained in liquids, meter slippage, meter wear). It is not to be confused with the "K Factor," which is used to convert the number of pulses generated by a meter (where electronic pulse technology is the basis of the meter operation) into units of volume. The K Factor is typically determined by the meter manufacturer and does not take into consideration all of the specific operational conditions the meter may be subjected to.

Metering Difference - The volume used to balance, on a monthly basis, any difference that occurs between the measured inlet/receipt volumes and the measured outlet/disposition volumes at a facility.

Methane - In addition to its normal scientific meaning, a mixture mainly of methane that ordinarily may contain some ethane, nitrogen, helium, or carbon dioxide.

Natural Gas Liquid (NGL) - Propane, butanes, or pentanes plus, or a combination of them, obtained from the processing of raw gas or condensate.

Oil - Condensate or crude oil, or a constituent of raw gas, condensate, or crude oil that is recovered in processing, that is liquid at the conditions under which its volume is measured or estimated.

Oil Battery - A system or arrangement of surface equipment receiving the effluent from one or more oil wells that provides separation, treating, measurement, and other oil handling functions prior to the delivery to market or other disposition.

Oilfield Waste – An unwanted substance or mixture of substances that results from the construction, operation, abandonment, or reclamation of a facility, well site, or pipeline, but does not include an unwanted substance or mixture of substances from such a source that is received for storage, treatment, disposal, or recycling at a facility that is regulated by the Department of Environment.

Oil Well - A well that produces primarily liquid hydrocarbons from a pool or portion of a pool wherein the hydrocarbon system is liquid or exhibits a bubble point on reduction of pressure, or any well so designated by the EUB.

Operator - With respect to a well or facility, a person who

- has control of or undertakes the day-to-day operations and activities at a well or facility, or
- keeps records and submits production reports for a well or facility to the EUB, whether or not that person is also the licensee or approval holder of the well or facility.

Outage Gauge - The distance from a reference point at the top of a tank to the surface of the liquid. This "gauge" is then subtracted from the full height gauge (from the same reference point) of the tank to determine the depth of the liquid.

Pentanes Plus - A mixture mainly of pentanes and heavier hydrocarbons, which ordinarily may contain some butanes, that is obtained from the processing of raw gas, condensate, or crude oil.

Pipeline - Any pipe or any system or arrangement of pipes wholly within Alberta and whereby oil, gas, or synthetic crude oil or water incidental to the drilling for or production of oil, gas or synthetic crude oil is conveyed, and

- includes all property of any kind used for the purpose of, in connection with, or incidental to the operation of a pipeline in the gathering, transporting, handling, and delivery of oil, gas, synthetic crude oil, or water, but
- does not include any pipe or any system or arrangement of pipes that constitutes a distribution system for the distribution within a community of gas to ultimate consumers.

Pool - A natural underground reservoir containing or appearing to contain an accumulation of oil or gas or both separated or appearing to be separated from any other such accumulation.

Propane - In addition to its normal scientific meaning, a mixture mainly of propane that ordinarily may contain some ethane or butanes.

Proration - An accounting procedure or system in which the total actual monthly battery production is equitably distributed among the wells in the battery.

Proration Battery - A battery for which all well production is commingled prior to the total battery production volumes being separated and measured (or estimated where appropriate) as single phases. Individual monthly well production volumes are estimated based on periodic well tests and are corrected to the actual monthly volumes through the use of proration factors.

Prover - A device used to collect and determine the volume of a sample of fluid that has passed through a meter. Provers typically use volumetric or gravimetric means to determine the quantity of the sample.

Prover Run - The operation of a prover or master meter whereby a representative volume is sampled and measured, and that sample volume is compared to the volume indicated by a meter through which the same sample has passed to determine a meter factor.

Proving - The procedures or operations whereby a prover volume is compared to an indicated meter volume (both corrected to applicable pressure and temperature conditions). The prover volume divided by the indicated meter volume yields a meter factor. The meter factor is subsequently applied to indicated meter volumes to determine the adjusted or corrected volume. If the meter is connected to an electronic readout, the meter factor may be incorporated into the software such that the indicated meter volume is already corrected to read the adjusted volume. (Care should be taken in such cases not to apply the meter factor again – in such cases the meter factor should be indicated on the tag or label as being 1.0000.)

Raw Gas - A mixture containing methane, other paraffinic hydrocarbons, nitrogen, carbon dioxide, hydrogen sulphide, helium, and minor impurities, or some of these, that is recovered or is recoverable at a well from an underground reservoir and is gaseous at the conditions under which its volume is measured or estimated.

Relative Density of Gas - The ratio of the mass of the gas to the mass of an equal volume of air. It is also referred to as gas gravity or specific gravity of gas.

S&W - "Sediments and water," commonly refers to settled solid and/or semi-solid components and water in tanks and other containment vessels.

Sales Gas - A mixture mainly of methane originating from raw gas, if necessary through the processing of the raw gas for the removal or partial removal of some constituents, and that meets specifications for use as a domestic, commercial, or industrial fuel or as an industrial raw material.

Satellite or Satellite Battery - Surface equipment located between a number of wells and the main battery that is intended to separate and measure the production from each well, after which the fluids are recombined and piped to the main battery for separation/treating, measurement, and storage or delivery.

Segregate - To confine each fluid in a well to its proper pool or flow channel so that it is separate from the fluid in or passing from or to any other pool.

Separator - An unfired apparatus specifically designed and used for separating fluids produced from a well into two or more streams; does not include a dehydrator.

Single Point Measurement Uncertainty - Relates to the limits applicable to equipment and/or procedures used to determine a specific volume at a single measurement point.

Solid - A substance that does not contain free liquids and is not gaseous at standard conditions.

Solution Gas - Volatile hydrocarbons that are dissolved in solution with produced oil or bitumen.

Stock Tank Vapours - The solution gas present in the oil/bitumen storage tanks that may be released from the tanks.

Synthetic Crude Oil - A mixture mainly of pentanes and heavier hydrocarbons, which may also contain sulphur compounds, that is derived from crude bitumen and is liquid at the conditions under which its volume is measured or estimated; includes all other hydrocarbon mixtures so derived.

Tank - A device designed to contain materials produced, generated, and used by the upstream petroleum industry that is constructed of impervious materials to provide structural support; may include such materials as concrete, plastic, fiberglass reinforced plastic, or steel.

Thief - An industry term for a bottom closure, core-type liquid sampling device used to secure samples from storage tanks.

Treater - A fired apparatus specifically designed and used for separating gas and water from crude oil.

Truck Terminal - A system or arrangement of tanks and other surface equipment that receives hydrocarbon liquids by truck for the purpose of delivering those liquids into a pipeline.

Well - An orifice in the ground completed or being drilled
- for the production of oil or gas,
- for injection to an underground formation,
- as an evaluation well or test hole, or
- to or at a depth of more than 150 m for any purpose;

does not include such an orifice for the purpose of discovering or evaluating a solid inorganic mineral that does not or will not penetrate a stratum capable of containing a pool or oil sands deposit.

Well Event - A unique identifier code for an interval, zone, pool, or horizon in a well. A well may be completed in multiple intervals, zones, pools, or horizons, each of which is identified as a well event.

Appendix 4 Water-Cut (S&W) Procedures

Water-cut procedures are divided into three categories and described on the following pages. Different procedures are specified for the three categories to improve accuracy and consistency of the S&W determinations. The use of "mason jars" with measuring tape attached is not acceptable for determining S&W. S&W percentage must be recorded to a minimum of one decimal place.

More detail on S&W determination is in API MPMS, Chapter 10.4: Determination of Water and/or Sediment in Crude Oil by the Centrifuge Method (Field Procedure). The EUB will consider any procedure that meets API MPMS, 10.4 standards to be in compliance with this directive. It is the responsibility of the licensee/operator to show that its procedure meets the above API standard.

Category 1—for 0 to 10% S&W

Obtain a representative sample of liquid.

Shake the sample container vigorously to mix it before pouring into the centrifuge tubes.

1) Fill each of two tubes with exactly 100 parts (50 ml) of the sample.
2) Fill each tube with the solvent solution (premixed solvent and demulsifier) to the 200-part mark (100 ml).
3) Stopper each tube tightly and invert 10 times.
4) Loosen the stoppers and immerse the tubes in a preheater. Heat the contents to 60°C ±3°C.
5) Stopper each tube tightly and invert 10 times.
6) Place the tubes in the centrifuge machine in a balanced condition and spin for 5 minutes.
7) Immediately after the centrifuge comes to rest, use a thermometer to verify that the sample temperature is within 9°C of the test temperature.

   If sample temperature is within 9°C, go to step 8. If sample temperature is not within 9°C, go back to step 4, raise the temperature, and repeat steps 5, 6, and 7.

8) Read and record the volume of water and sediment at the bottom of each tube.
9) Reheat the tubes to the initial spin temperature and return them, without agitation, to the centrifuge machine. Spin for an additional 5 minutes. Repeat the procedure until two consecutive, consistent readings are obtained.

   For the test to be considered valid, a clear interface must be observed between the oil layer and the separated water. No emulsion should be present immediately above the oil/water interface. A test comprises TWO TUBES of the SAME SAMPLE. Compare the readings of the two tubes. If the difference is greater than one subdivision on the centrifuge tube, the test is invalid and should be repeated.

10) Calculation and reporting:

For 200 ml tubes: the percentage of water and sediment is the average, to three decimal places, of the values read directly from the two tubes.

For 100 ml tubes: read and record the volume of water and sediment in each tube. Add the readings together and report the sum as the percentage of water and sediment.

Example 1 (see Figure A4.1)

100 ml centrifuge tubes	200 ml centrifuge tubes
If reading from each tube is the same:	
Reading from each tube = 0.50 ml	Reading from each tube = 1.00 ml
Water cut = (0.50 + 0.50) ÷100 = 1.0 %	Water cut = 1.00 ÷ 100 = 1.0 %
If reading from each tube is not the same:	
Reading from 1st run of each tube = 0.50, 0.60 ml	Reading from 1st run of each tube = 1.00, 1.05 ml
Reading from 2nd run of each tube = 0.50, 0.55 ml	Reading from 2nd run of each tube = 1.00, 1.10 ml
Water cut = (0.50 + 0.60 + 0.50 + 0.55) ÷ 2 ÷ 100 = 1.1%	Water cut = (1.00 + 1.05 + 1.00 + 1.10) ÷ 4 ÷ 100 = 1.0%

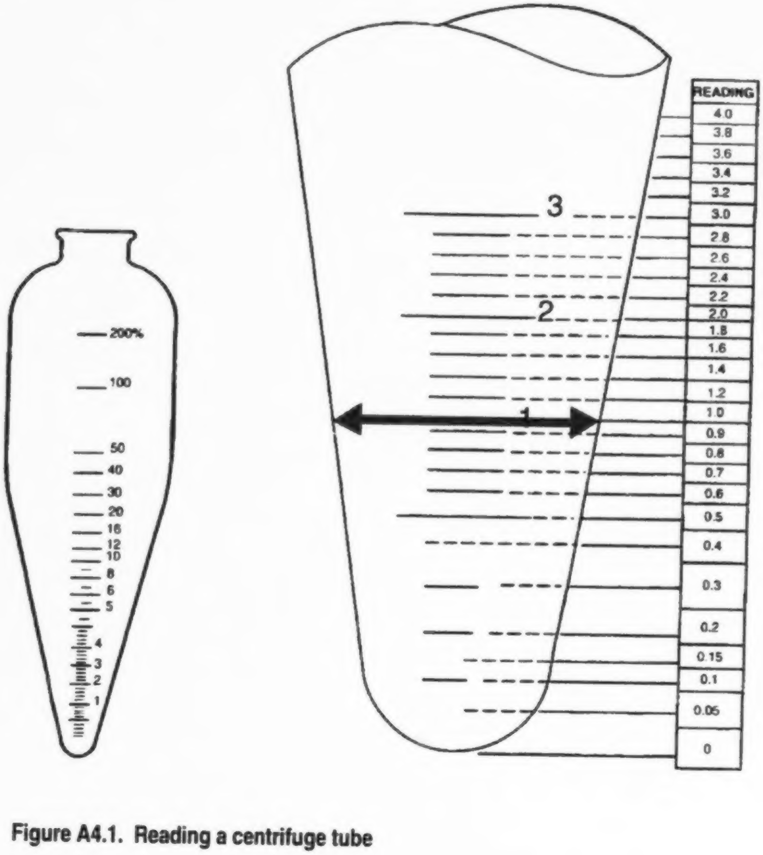
200%
100
50
40
30
20
16
12
10
8
6
5
4
3
2
1
3
2
1
READING
4.0
3.8
3.6
3.4
3.2
3.0
2.8
2.6
2.4
2.2
2.0
1.8
1.6
1.4
1.2
1.0
0.9
0.8
0.7
0.6
0.5
0.4
0.3
0.2
0.15
0.1
0.05
0

Figure A4.1. Reading a centrifuge tube

Category 2—for 10 to 80% S&W

Obtain the maximum representative sample of liquid feasible (minimum 800 ml).

Transfer the entire sample into an adequately sized graduated cylinder. It may be necessary to wash out the inside of the sample container with a measured volume of solvent to ensure that all of the oil is removed. If this is done, it is necessary to account for the additional amount of solvent added when calculating the water-cut percentage.

Place the graduated cylinder into a heat bath at or above treater temperature (or at or above 60°C if no treater is involved) until the sample temperature and free water fallout have stabilized. A clear oil/water interface must be visible.

Read and record the total volume, the volume of free water, and the volume of oil/emulsion in the graduated cylinder. Calculate the free water percentage as follows:

Percentage of free water = (Volume of free water ÷ Total volume) x 100%

If solvent and/or demulsifier is added to the sample at any stage of this procedure, it must be accounted for in the calculation as follows:

Percentage of free water =

Volume of free water ÷ (Total volume – Volume of solvent/demulsifier) x 100%

Draw 100 ml from the oil/emulsion portion in the graduated cylinder and fill each of two 100 ml centrifuge tubes to exactly the 50 ml mark. Add solvent to bring the level in the tubes to exactly the 100 ml mark. The procedures previously outlined for samples with 0 to 10% water cut are to be followed, with the exception that the water-cut readings from both tubes are to be added together, even if they are not the same.

Note that if 200 ml tubes are to be used, a larger initial sample will be required, and if the water-cut readings from both tubes are not the same, the average of both tubes is to be used as the resultant water cut of the oil/emulsion portion.

From the spinning results, calculate the percentage of water remaining in the oil/emulsion portion as follows:

Percentage of water remaining =

Total oil/emulsion volume in cylinder x Water-cut % of oil/emulsion ÷ Total volume

If solvent and/or demulsifier is added to the sample at any stage of this procedure, it must be accounted for in the calculation as follows:

Percentage of water remaining =

(Total oil/emulsion volume in cylinder x Water-cut % of oil/emulsion) ÷ (Total volume – Volume of solvent/demulsifier)

Calculate the total water-cut percentage as follows:

Total water-cut % = % free water + % water remaining

Example 2 (see Figure A4.2)

1000 ml graduated cylinder

% of free water = 600 ml ÷ 900 ml x 100% = **66.7%**

% of water remaining = 300 ml x 10%* ÷ 900 ml = **3.3%**

Total Water-cut % = 66.7% + 3.3%= **70.0%**

* Water cut of oil portion determined by spinning samples

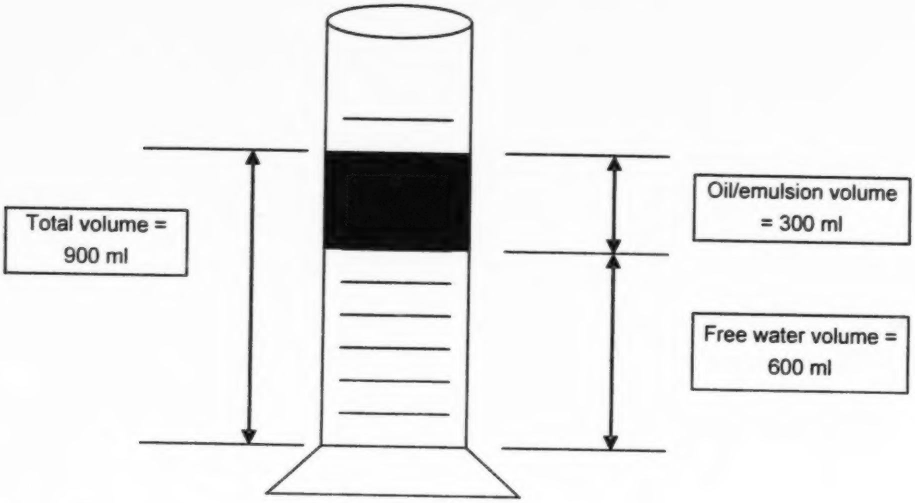

Figure A4.2. Water-cut % from 10 to 80%

Category 3—for 80 to 100% S&W

Obtain the maximum representative sample of liquid feasible (minimum 800 ml).

Transfer the entire sample into an adequately sized graduated cylinder. It may be necessary to wash out the inside of the sample container with a measured volume of solvent to ensure that all of the oil is removed. If this is done, it is necessary to account for the additional amount of solvent added when calculating the water-cut percentage.

Place the graduated cylinder into a heat bath at or above treater temperature (or at or above 60°C if no treater is involved) until the sample temperature and free water fallout have stabilized. A clear oil/water interface must be visible. A narrow-necked graduated cylinder should be used to improve accuracy in sample measurement when the water cut is above 90% (see Figure A4.4).

Read and record the total volume and the volume of free water in the graduated cylinder. If no solvent or demulsifier has been added to the sample, calculate the water-cut percentage as follows:

Water-cut % = Volume of free water ÷ Total volume x 100%

If solvent and/or demulsifier is added to the sample at any stage of this procedure, it must be accounted for in the calculation as follows:

Water-cut % = Volume of free water ÷ (Total volume - Volume of solvent/demulsifier) x 100%

The water content of the oil/emulsion portion in the graduated cylinder does not have to be determined, due to the limited amount of the oil/emulsion portion of the sample available at these high water contents. However, if there is enough oil/emulsion volume, the licensee may choose to use the same procedure as that described for the 10 to 80% S&W, with the option to centrifuge only one sample.

Example 3 (see Figure A4.3)

1000 ml graduated cylinder
Water-cut % = 900 ml ÷ 1000 ml x 100% = 90.0%

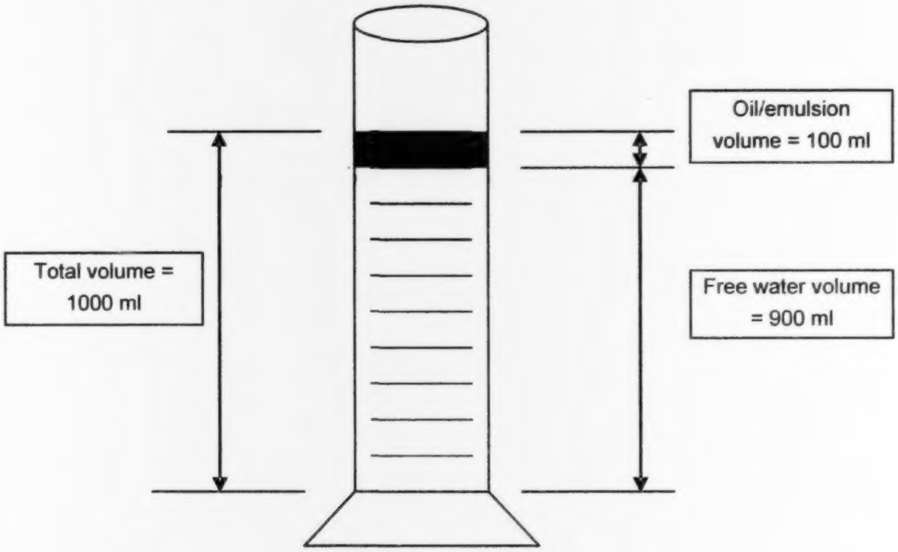
Oil/emulsion volume = 100 ml
Total volume = 1000 ml
Free water volume = 900 ml

Figure A4.3. Water-cut % over 80%

Figure A4.4. Narrow-necked graduated cylinder